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Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in GE-Designed Operating Plants and Near-Term Operating License Applications

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Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in GE-Designed Operating Plants and Near-Term Operating License Applications

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SUMMARY AND CONCLUSIONS

The accident at Three Mile Island Unit 2 (TMI-2) on March 28, 1979, involved a main feedwater transient coupled with a stuck-open pressurizer power-operated relief valve and a temporary failure of the auxiliary feedwater system. The resulting severity of the ensuing events and the potential generic aspects of the accident on other operating reactors led the NRC to initiate prompt action to: (a) assure that other reactor licensees, particularly those with plants similar in design to TMI-2, took the necessary actions to substantially reduce the likelihood for TMI-2 type events, and (b) investigate the potential generic implications of this accident on other operating plants.

The Bulletins & Orders Task Force (B&OTF) was established within the NRC Office of Nuclear Reactor Regulation in early May 1979 and discontinued operations on December 31, 1979. This task force was responsible for reviewing and directing the TMI-2-related staff activities associated with loss of feedwater transients and small-break loss-of-coolant accidents for all operating plants to assure their continued safe operation. In conducting this activity, the B&OTF concentrated its efforts on: (1) the assessment of systems reliability, (2) the review of analytical predictions of plant performance for both feedwater transients and small-break loss-of-coolant accidents, (3) the evaluation of generic operator guidelines, (4) the review of emergency plant operating procedures, and (5) the review of operator training.

This report summarizes the results of the B&OTF's generic evaluation of feedwater transients, small-break loss-of-coolant accidents, and other TMI-2-related events for General Electric Company-designed operating plants and near-term operating license applications to confirm or establish the bases for the continued safe operation of the operating plants. The results of this evaluation are presented in this report.

The B&OTF's generic review of the General Electric Company-designed operating plants and near-term operating license applications has resulted in the following conclusions.

(1) The continued operation of the General Electric Company-designed operating plants is acceptable provided that certain actions related to the plants' designs and operation, and training of operators identified in this report are implemented consistent with the recommended implementation schedule.

(2) The actions taken by the licensees with General Electric Company-designed operating plants in response to Office of Inspection and Enforcement Bulletin 79-08 provide added assurance for the protection of the health and safety of the public.

In addition, the B&OTF has independently confirmed the safety significance of those related actions recommended by other Office of Nuclear Reactor Regulation task forces as discussed in this report.

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1. INTRODUCTION

1.1 Background

The accident at Three Mile Island Unit 2 (TMI-2) on March 28, 1979, involved a main feedwater transient coupled with a stuck-open pressurizer power-operated relief valve and a temporary failure of the auxiliary feedwater system. The resulting severity of the ensuing events and the potential generic aspects of the accident on other operating reactors led the NRC to initiate prompt action to: (a) assure that other reactor licensees, particularly those with plants similar in design to TMI-2, took the necessary actions to substantially reduce the likelihood for TMI-2 type events, and (b) investigate the potential generic implications of this accident on other operating plants.

This report summarizes the results of our generic evaluation of feedwater transients, small-break loss-of-coolant accidents (LOCAs), and other TMI-2-related events for General Electric Company (GE)-designed operating plants and near-term operating license applications (see Table 1-1) to confirm or establish the bases for the continued safe operation of the operating plants. The results of this evaluation are presented in this report in the form of a set of findings and recommendations in each of the principal review areas. Additional review of the accident is continuing and further information is being obtained and evaluated. Any new information will be reviewed and modifications will be made as appropriate.

1.2 Bulletins & Orders Task Force

The Bulletin & Orders Task Force (B&OTF) was established within the Office of Nuclear Reactor Regulation (NRR) in early May 1979 and discontinued operations on December 31, 1979. The B&OTF was responsible for reviewing and directing the TMI-2 related staff activities associated with loss of feedwater transients and small-break LOCAs for all operating plants to assure their continued safe operation. In conducting this activity, the B&OTF concentrated its efforts on: (1) the assessment of systems reliability, (2) the review of analytical predictions of plant performance for both feedwater transients and small-break LOCAs, (3) the evaluation of generic operator guidelines, (4) the review of emergency plant operating procedures, and (5) the review of operator training.

The B&OTF worked directly with the operating plant licensees on plant-specific matters. For the review of generic items, a working relationship was established with owners groups for plants designed by each nuclear steam supply system (NSSS) vendor (Babcock & Wilcox Company, Westinghouse Electric Corporation, Combustion Engineering, Incorporated and GE) and with the individual nuclear steam supply system vendors themselves. Initial priority was placed on plants of the Babcock & Wilcox design. As short-term actions on these plants were completed, priority was shifted to those pressurized water reactor (PWR) plants designed by Westinghouse and Combustion Engineering. Activities relating to boiling water reactor (BWR) plants, a significantly different light water reactor plant type, were pursued as a third priority. All BWR plants incorporated NSSS's designed by GE except for the LaCrosse plant whose NSSS was designed by Allis Chalmers.

TABLE 1-1

BOILING WATER REACTOR PLANTS EVALUATED BY THE BULLETINS & ORDERS TASK FORCE

Plant	BWR Type	Utility	Power Level	Operating License Date
Big Rock Point	1	Consumers Power Co.	240	08/30/62
Browns Ferry 1	4	Tennessee Valley Authority	3293	06/26/73
Browns Ferry 2	4	Tennessee Valley Authority	3293	06/28/74
Browns Ferry 3	4	Tennessee Valley Authority	3293	07/02/76
Brunswick 1	4	Carolina Power & Light Co.	2436	09/08/76
Brunswick 2	4	Carolina Power & Light Co.	2436	10/27/74
Cooper	4	Nebraska Public Power District	2381	01/18/74
Dresden 1	1	Commonwealth Edison Co.	700	09/28/59
Dresden 2	3	Commonwealth Edison Co.	2527	12/22/69
Dresden 3	3	Commonwealth Edison Co.	2527	01/12/71
Duane Arnold	4	Iowa Electric Light & Power Co.	1658	02/22/74
FitzPatrick	4	Power Authority of the State of NY	2436	10/17/74
Hatch 1	4	Georgia Power Co.	2436	08/06/74
Hatch 2	4	Georgia Power Co.	2436	06/13/78
Humboldt Bay	1	Pacific Gas & Electric Co.	220	08/28/62
LaSalle 1*	5	Commonwealth Edison Co.	3293	-
LaSalle 2*	5	Commonwealth Edison Co.	3293	-
Millstone 1	3	Northeast Nuclear Energy Co.	2011	10/06/70
Monticello	3	Northern States Power Co.	1670	09/08/70
Nine Mile Point 1	2	Niagra Mohawk Power Co.	1850	08/22/69
Oyster Creek	2	Jersey Central Power & Light Co.	1930	04/09/69
Peach Bottom 2	4	Philadelphia Electric Co.	3293	08/08/73
Peach Bottom 3	4	Philadelphia Electric Co.	3293	07/02/74
Pilgrim 1	3	Boston Edison Co.	1998	06/08/72
Quad Cities 1	3	Commonwealth Edison Co.	2511	10/01/71
Quad Cities 2	3	Commonwealth Edison Co.	2511	03/31/72
Shoreham*	4	Long Island Lighting Co.	2436	-
Vermont Yankee	4	Vermont Yankee Nuclear Power Co.	1593	03/21/72
Zimmer*	5	Cincinnati Gas & Electric Co.	2436	-

---

*Plants with near-term operating license applications.

The B&OTF was composed of approximately thirty technical professionals in widely varying disciplines and areas of expertise. The Director of the B&OTF was Dr. D. F. Ross, Jr., and the Deputy Director was T. M. Novak. The organization of the B&OTF is shown in Figure 1-1.

The charter and scope of activities of the B&OTF are discussed in Sections 1.2.1 and 1.2.2 of this report, respectively. Section 1.2.3 of this report summarizes the B&OTF activities regarding: (1) the evaluation of licensees' responses to the Office of Inspection and Enforcement (IE) bulletins, (2) the issuance and subsequent lifting of Commission Orders issued to licensees with Babcock & Wilcox (B&W)-designed operating plants, and (3) the evaluation of the systems reliability and predicted plant performance for the designs of each of the other reactor vendors with regard to feedwater transients and small-break LOCAs.

1.2.1 Charter

The charter of the B&OTF was to review the generic implications of the TMI-2 accident for all operating plants to confirm the bases for their continued safe operation. The end products for this task included:

(1) Safety evaluations and authorizations to resume or continue operations.

(2) Licensing positions regarding the implementation of short-term measures on operating light water reactor plants.

(3) Recommendations for further improvements in the areas of design and operation, and administrative procedures.

(4) Notification of the Lessons Learned Task Force* of any required actions identified during the B&OTF review.

1.2.2 Scope of Activities

The scope of the B&OTF activities was limited to the review of loss of feedwater transients and small-break LOCAs. The specific areas of review related to these events are as follows:

(1) Reliability of systems.

(2) Analyses.

(3) Guidelines for the preparation of emergency operating procedures.

(4) Training of operators in emergency operating procedures.

---

*The Lessons Learned Task Force was also formed in NRR in response to the TMI-2 accident to identify and evaluate those safety concerns originating with the TMI-2 accident that required licensing actions (beyond those that had been specified in IE bulletins and Commission Orders) for currently operating reactors, as well as for pending operating license and construction permit applications. For this reason, the scope of the Lessons Learned Task Force was more general than the scope of the B&OTF.

Figure 1-1

BULLETINS & ORDERS TASK FORCE ORGANIZATION

D. F. Ross, Jr., Director

T. M. Novak, Deputy Director

Projects Group*
W. Kane, Group Leader

I. Villalva, Alternate
P. O'Reilly
C. Thomas
R. Capra
J. Lee, Licensing Assistant

Systems Group
S. Israel, Group Leader

Section A
G. Mazetis
Section Leader

F. Ashe
W. LeFave
G. Kelly
M. Rubin
K. Mahan
D. Thatcher

Section B
P. Matthews
Section Leader

W. Hodges
J. Joyce
C. Liang
N. Wagner
B. Siegel
T. Greene
B. Wilson

Analysis Group
Z. Rosztoczy, Group Leader

P. Norian, Alternate
R. Audette
B. Sheron
W. Jensen
E. Throm
J. Guttman
R. Frahm

---

*C. J. Heltemes, Jr., served as group leader of the Projects Group until late September 1979.

In conducting its activities, the B&OTF had an overlapping responsibility with certain of the short-term Lessons Learned items as indicated below:

(1) Item 2.1.3b (Part 1 only) - Instrumentation for Inadequate Core Cooling (Develop Procedures and Describe Existing Instrumentation)

(2) Item 2.1.7a - Auto Initiation of Auxiliary Feed

(3) Item 2.1.7b - Auxiliary Feed Flow Indication

(4) Item 2.1.9 - Transient and Accident Analysis

These items are described in detail in NUREG-0578, "TMI-2 Lessons Learned Task Force Status and Short-Term Recommendations." The B&OTF reviewed the licensees' responses to these short-term Lessons Learned items since these requirements were identified in the generic reviews conducted by the B&OTF.

1.2.3 Summary of Activities

IE Bulletins

The staff's preliminary review of the TMI-2 accident identified several errors and malfunctions that occurred during the accident that contributed significantly to its severity. As a result, all holders of operating licenses were subsequently instructed to take a number of immediate actions to avoid repetition of these errors. These instructions were specified in a series of bulletins issued by IE.

The initial IE bulletins defined actions to be taken by the licensees of operating plants with Babcock & Wilcox-designed NSSSs. As the staff's evaluation continued, it was determined that additional actions were necessary. These bulletins were subsequently expanded, clarified, and issued to the licensees of all operating plants for action. Holders of operating licenses for Babcock & Wilcox-designed reactors were instructed by IE bulletins to take further actions, including immediate changes to decrease the reactor high pressure trip setpoints and increase the pressurizer power-operated relief valve setpoints.

The B&OTF directed the evaluation of each licensee's response to the IE bulletins. This evaluation process involved an inter-office review group, which included representatives from IE and from the NRR Division of Operating Reactors. When it was concluded that a licensee understood and provided an acceptable response to the bulletins, the bulletin review was completed and the evaluation was issued as a staff report.

The prompt action taken by licensees in response to the IE bulletins was considered to be an important contributor to assuring continued safe plant operation. In addition, the bulletins and related evaluations provided substantive input to other staff activities, such as those associated with the generic study efforts and the Lessons Learned Task Force. Thus, many of the subjects addressed by the bulletins were considered in greater depth through other staff activities and studies. Further, the bulletins and the associated licensees' responses served as bases for inspecting plants and auditing reactor operator training.

Orders on B&W-Designed Plants

Soon after the TMI-2 accident, the NRC staff began a reevalution of the design features of B&W-designed plants to determine whether additional safety corrections or improvements were necessary. This evaluation involved numerous meetings with B&W and the affected licensees.

The conclusion of these preliminary studies was documented in an April 25, 1979, status report to the Commission. It was found that the B&W-designed plants appeared to be unusually sensitive to certain transient conditions originating in the secondary system. The features of the B&W-designed plants that contributed to this sensitivity were (1) the relatively small liquid volumes in the secondary side of the steam generators, (2) lack of direct initiation of reactor trip upon the occurrence of off-normal conditions in the feedwater system, (3) reliance on an integrated control system to automatically regulate feedwater flow, (4) actuation before reactor trip of a power-operated relief valve on the primary system pressurizer (which, if the valve sticks open, can aggravate the event), and (5) a low steam generator elevation relative to the reactor vessel provides a smaller driving head for natural circulation (except for the Davis-Besse plant).

Because of these features, the B&W-designed plants rely more than other PWR designs on the reliability and performance characteristics of the auxiliary feedwater system, the integrated control system, and the emergency core cooling system performance for certain anticipated transients such as loss of offsite power and loss of normal feedwater. This, in turn, can require greater operator knowledge and skill to safely manage the plant controls during such anticipated transients. As a result of the work supporting the April 25, 1979, report, the NRC staff concluded that certain other short-term design and procedural changes at B&W-designed operating plants were necessary in order to assure adequate protection to public health and safety.

After a series of discussions between the NRC staff and licensees of operating B&W-designed plants, the licensees agreed to shut down these plants until the actions identified to the Commission in the April 25, 1979, report could be completed. This agreement was confirmed by a Commission Order to each of the licensees. Authorizations to resume operation were issued during the period late May through early July 1979, as individual licensees satisfactorily completed the short-term actions and the NRC staff completed an onsite verification of the plant readiness to resume operation. In addition to the modifications to be implemented promptly, each licensee also proposed to carry out certain additional long-term modifications to further enhance the capability and reliability of the plant systems to cope with transient events.

Some of the long-term modifications involve the design, procurement, and qualification of safety-grade hardware. Therefore, all of the actions of the long-term portion of the Commission Orders have not yet been completed. NRC staff involvement will continue to assure that licensees complete each long-term action of the Commission Orders "as promptly as practicable," and that the Commission Orders are closed out by a prompt NRC staff acceptance review.

Generic and Plant-Specific Studies

For B&W-designed operating reactors, an initial NRC staff study was completed and published in NUREG-0560, "Staff Report on the Generic Assessment of Feedwater Transients in Pressurized Water Reactors Designed by the Babcock & Wilcox Company." This study considered the particular design features and operational history of B&W-designed operating plants in light of the TMI-2 accident and related current licensing requirements. As a result of this study, a number of findings and recommendations resulted which are now being pursued.

Generally, the activities involving the B&W-designed reactors are reflected in the actions specified in the Commission Orders. Consequently, as noted earlier, a number of actions have been specified regarding transient and small-break analyses, upgrading of auxiliary feedwater reliability and performance, procedures for operator action, and operator training. The results of the NRC staff review of the B&W small-break analysis is published in NUREG-0565, "Generic Evaluation of Small-Break Loss-of-Coolant Accident Behavior in Babcock & Wilcox-Designed Operating Plants."

Similar studies have been completed for the Westinghouse and, Combustion Engineering-designed operating plants. These studies, which also focus specifically on the predicted plant performance under different accident scenarios involving feedwater transients and small-break loss-of-coolant accidents, are published in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small-Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants," and NUREG-0635, "Generic Evaluation of Feedwater Transients and Small-Break Loss-of-Coolant Accidents in Combustion Engineering-Designed Operating Plants," respectively.

1.3 Conclusions

Based on our generic review of the GE-designed operating plants and near-term operating license applications, we have reached the following conclusions:

(1) The continued operation of the GE-designed operating plants is acceptable provided that certain actions related to the plants' designs and operation, and training of operators identified in Section 4.0 of this report are implemented consistent with the recommended implementation schedule.

(2) The actions taken by the licensees with GE-designed operating plants in response to IE Bulletin 79-08 provide added assurance for the protection of the health and safety of the public.

In addition, the B&OTF has independently confirmed the safety significance of those related actions recommended by other NRR task forces as discussed in this report.

2. LICENSING BASES AND REGULATIONS

The principal elements of the NRC requirements for the design and operation of nuclear power plants are contained in the Code of Federal Regulations, Title 10, Part 50; especially in Appendix A, General Design Criteria (GDC). To assure a consistent review of each plant's Safety Analysis Report by NRC, a Standard Review Plan (NUREG-75/087) was developed.

The basic requirements for anticipated operational occurrences are given in GDC 10 and GDC 15. Additional requirements are specified in GDC 13 and GDC 14. These criteria appear to have been met for BWRs, even in light of the TMI-2 experience.

The Standard Review Plan requirements in Section 15.2.7 for the loss of feedwater and other anticipated transients in Section 15.2.7 provide that transients be reviewed to the point where a stabilized condition is achieved. The staff has accepted analyses in Safety Analysis Reports in which the critical parameters had not entered a stable condition, but which were terminated at the time of high pressure injection. This will no longer be acceptable. Further, Section 15.1 of the Standard Review Plan provides that an incident of moderate frequency in combination with any single active component failure, or single operator error, should not result in a loss of function of any barrier other than fuel cladding. A limited number of fuel rod cladding perforations is acceptable. The staff has been aware that anticipated operational occurrences plus a single failure are not rigorously pursued, especially with regard to a stuck-open safety/relief valve during a transient. Such events were considered either to be within the capability of the makeup system or were covered by small-break LOCA analyses.

In no case, however, would the present Standard Review Plan require that multiple failures similar to those apparently associated with the TMI-2 event be considered as design basis events. Further discussion of this matter is provided in Appendix D to this report.

3. OFFICE OF INSPECTION AND ENFORCEMENT BULLETINS

On April 14, 1979, IE Bulletin 79-08, "Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident," was issued for action to the licensees of all BWR plants with operating licenses and for information to the licensees of all other plants with construction permits or operating licenses. Followup actions required of BWR plant licensees in response to IE Bulletin 79-08 included (1) those that required reviews of information provided in the bulletin and assessments by the licensees as to the need for changes at the plants, and (2) those that required the implementation of changes in specific design features or operating procedures at the plants.

Our review of the licensees' responses to IE Bulletin 79-08 is complete. Requests for further information and clarification of individual licensee's responses have been made to facilitate the review of these responses.

Separate evaluation reports for each BWR operating plant are being prepared to document our evaluation of each licensee's response to IE Bulletin 79-08. These reports state our conclusions regarding the licensee's responsiveness to each of the bulletin action items. They also indicate whether the licensee (1) has correctly interpreted the bulletin, (2) has demonstrated its understanding of the concerns arising from the TMI-2 accident and its implications for the licensee's own operations, and (3) has provided added assurance for the protection of the public health and safety during plant operation.

4. GENERAL FINDINGS AND RECOMMENDATIONS

We have reviewed the GE-designed BWR plants to assess their adequacy in coping with small-break LOCAs and loss of feedwater transients, with or without a safety/relief valve stuck open. Because of the accident at TMI-2, this review encompassed the performance of safety and non-safety systems and included the effects of multiple system failures. The purpose of this review was to determine whether continued operation of BWR plants is acceptable in light of the TMI-2 accident.

On the basis of our review, we concluded that the GE-designed BWR systems are quite capable of coping with small-break LOCAs and with feedwater transients with or without stuck-open safety/relief valves. Therefore, we conclude that continued operation of the GE-designed BWRs is acceptable. The GE-designed BWRs have multiple safety systems which can provide core cooling in the event of transients and accidents. The ability to quickly depressurize and use low pressure systems if the high pressure systems fail adds significantly to the capability of GE-designed BWRs to cope with the events reviewed. Also, the GE-designed BWRs are designed to operate with voids in the upper part of the reactor vessel as well as with natural circulation of coolant through the core.

Our review did, however, identify improvements in systems, procedures, and analysis which will make the GE-designed BWRs less susceptible to core damage during accidents and transients coupled with systems failures or operator errors. These improvements, which constitute the recommendations of the B&OTF, are listed below. Citations in parentheses next to each recommendation designation refer to the appendix(es) section(s) in this report in which the recommendation is discussed in more detail.

4.1 Licensing Positions Regarding Implementation of Short-Term Measures

A.1 (A-2.3). Currently, the reactor core isolation cooling (RCIC) system and the high pressure coolant injection (HPCI) system both initiate on the same low water level signal and both isolate on the same high water level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the RCIC system initiation logic should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed by GE to evaluate these changes. The analyses should be submitted to staff and changes should be implemented if justified by the analyses.

A.2 (A-2.4). Isolation condensers have radiation monitors on their vents. These monitors provide alarms in the control room but do not isolate the isolation condenser. The isolation condensers are currently isolated on a high radiation signal in the steam line leading to the isolation condensers. The design should be modified such that the isolation condensers are automatically isolated upon receipt of a high radiation signal at the vent rather than at the steam line. The purpose of the change is to increase the availability of the isolation condensers as heat sinks.

A.3 (A-2.3, A-2.5, F-3.5). The HPCI and RCIC systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe break detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause system isolation.

A.4 (A-2.8, F-3.4). The record of relief valve failures to close for all BWRs in the past three years of plant operation is approximately 30 in 73 reactor years (0.41 failures/reactor year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small-break LOCA. The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures/challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

(1) Additional anticipatory scram on loss of feedwater,
(2) Revised relief valve actuation setpoints,
(3) Increased emergency core cooling (ECC) flow,
(4) Lower operating pressures,
(5) Earlier initiation of ECC systems,
(6) Heat removal through emergency condensers,
(7) Offset valve setpoints to open fewer valves per challenge,
(8) Installation of additional relief valves with a block or isolation valve feature to eliminate opening of the safety/relief valves (SRVs), consistent with the ASME code,
(9) Increasing the high steam line flow setpoint for main steam line isolation valve (MSIV) closure,
(10) Lowering the pressure setpoint for MSIV closure,
(11) Reducing the testing frequency of the MSIVs,
(12) More stringent valve leakage criteria, and
(13) Early removal of leaking valves.

GE should investigate the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

A.5 (A-2.9). Emergency procedures should include verification that a source of cooling water, such the as core spray, LPCI, or condensate systems, is available prior to manual actuation of the automatic depressurization system (ADS). Alternate water sources should be identified in the procedures and reference should be made to procedures for start-up and operation of systems that provide these sources. This is being implemented through the guidelines being developed to assure adequate core cooling.

A.6 (F-3.5). Several components of the ECC systems are permitted by Technical Specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last five years of operation. The report should also include the causes of the outages (e.g., controller failure, spurious isolation).

A.7 (A-2.9, F-3.5). The ADS actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme which should be considered is ADS actuation on low reactor vessel water level provided no HPCI or HPCS system flow exists and a low pressure ECC system is running. This logic would complement, not replace, the existing ADS actuation logic.

A.8 (A-2.17). Interlocks should be installed on non-jet pump plants (other than Humboldt Bay) to assure that at least two recirculation loops are open for recirculation flow for modes other than cold shutdown. This is to assure that the level measurements in the downcomer region are representative of the level in the core region.

A.9 (A-2.13). The service water system for Big Rock Point has only one cooling train and is powered from normal alternating current power. The Big Rock Point licensee should verify the acceptability of the consequences of a loss of service water supply to the essential plant components in the event of a loss of offsite power.

A.10 (A-2.7). The core spray and LPCI system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The core spray and LPCI system logic should be modified so that these systems will restart if required to assure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

A.11 (H-4.0). In order to assure that all operators have at least read all emergency procedures prior to assuming their on-shift duties, all operators should, as a minimum, be required to read all emergency procedures that have been implemented or modified since their previous shift.

A.12 (F-4.1). The analysis methods used by GE for small-break LOCA analyses for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the Two-Loop Test Apparatus (TLTA) facility.

A.13 (F-4.0). Plant-specific calculations using the NRC-approved model for small-break LOCAs as described in Recommendation A.12 above to show compliance with Appendix K to 10 CFR Part 50 should be submitted for NRC approval by all licensees.

A.14 (F-4.3). For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve should be included in this category.

A.15 (F-4.3). Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

A.16 (F-3.5). To assure that adequate manpower is available during an accident, there should be at least two operators in the control room during reactor operation. One of the two required operators in the control room should be designated to restart the high pressure safety injection systems (e.g., HPCI or RCIC system) if needed. This requirement is expected to be superseded by the requirements of the NRC TMI-2 Action Plan.

A.17 (F-4.6). GE should provide a response to the Michelson concerns as they relate to BWRs.

4.2 Recommendations for Further Improvements in Design, Operation, and Procedures

B.1 (A-2.3). The RCIC system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatic. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

B.2 (A-2.17). In order to simplify the reading of the water level in the vessel and to provide the operators with a record of water level during transients, all BWRs should have the capability to record vessel water level over the range from the top of the vessel dome to the lowest pressure tap. This range of water level should be available in one location on recorders which meet normal post-accident recording requirements. The recorders should be started on a reactor trip signal.

B.3 (A-2.13). Long-term operation of the RCIC and HPCI systems may require space cooling to maintain the pump room temperatures within allowable limits. The licensees should verify for each plant the acceptability of the consequences of a complete loss of alternating current power. The RCIC and HPCI systems should be designed to withstand a complete loss of alternating current power to their support systems, including coolers, for at least two hours.

B.4 (A-2.14). The licensees should determine by analysis or experiment, on a plant specific basis, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current power for at least two hours. Adequacy of the seal design should be demonstrated.

B.5 (A-2.6). The residual heat removal (RHR) system is used for shutdown cooling, low pressure coolant injection (LPCI), containment and suppression pool cooling, and fuel pool cooling. If the RHR system is needed for LPCI or containment cooling function at the same time as fuel pool cooling, the LPCI or containment cooling functions would take priority. Resultant boiling in the fuel pool could impair the capability of auxiliary systems not designed for a steam environment. Therefore, the RHR system should be dedicated to shutdown cooling, LPCI, and containment and suppression pool cooling. Fuel pool cooling systems should be self-sufficient. However, before making the change, GE should provide a risk assessment for using the RHR system for fuel pool cooling.

B.6 (A-2.17). Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points.

B.7 (A-2.15). Safety analysis reports claim that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that ECC systems are designed to withstand a hostile environment and still perform their function 100 days after an accident. GE should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, GE must show that the accumulator design is still acceptable.

B.8. The emergency operating procedures presently in use at operating BWR plants should be restructured and reformatted on a "symptom" basis, as opposed to the more "event-specific" basis on which these procedures have evolved. The symptom-based emergency procedures would be categorized according to general plant symptoms, such as loss-of-coolant inventory, as opposed to the several separate existing associated procedures such as LOCA inside containment, LOCA outside containment, and loss of normal feedwater. The loss-of-coolant inventory procedure would include the essential features of those existing procedures associated with LOCA inside containment, LOCA outside containment, and loss of normal feedwater, but would make use of the fact that the initial operator responses for the latter procedures are similar. The symptom-based emergency procedures should be implemented on a schedule consistent with the NRC TMI-2 Action Plan.

B.9 (F-4.4). Appropriate test programs should be developed for the purpose of verifying the BWR small-break LOCA models. The staff requires pretest predictions of future programs.

B.10 (F-4.3). All cooling systems required to prevent core uncovery must be qualified as ECC systems. As an example, if the RCIC system is required to prevent core uncovery, then it should be upgraded to qualify as an ECC system (e.g., incorporate diverse actuation signals).

B.11 (F-4.3). Plant simulators used for operator training should offer, as a minimum, the following small-break LOCA events:

(1) Continuous depressurization,
(2) Pressure stabilizing above the low pressure initiation setpoints,
(3) Repressurization, and
(4) Repressurization resulting in a stuck-open safety/relief valve.

Each of these events should be simulated with breaks occurring at different locations in the system. Breaks in the steam lines, recirculation lines, feedwater lines, and the control rod drive lines should be modeled and incorporated for use in operator training. In addition to the usual single failures in the ECC and feedwater systems, complete loss of high pressure injection systems should also be simulated in conjunction with the above events. To verify that simulators used for operator training provide adequate means of modeling adverse reactor responses when providing atypical challenges to the reactor operator, selective operating reactor transients should be programmed into the simulator and plant operators who have experienced the transient should evaluate the simulator's ability to depict actual plant responses. These transients should then be incorporated for use in operator training at all facilities.

B.12 (F-4.3). The GE small-break LOCA analyses relied on equipment which has not previously been identified as part of the reactor protection system or part of the engineered safety features systems. The systems used to terminate ECC and feedwater flow on high vessel water level and the relief portion of the safety/relief valves fall into this category. The reliability and redundancy of this equipment should be reviewed and upgraded if needed to comply with the requirements of Section 9 of Appendix A to NUREG-0585, "TMI-2 Lessons Learned Task Force Final Report," regarding the interaction of non-safety and safety-grade systems.

B.13 (F-4.5). If natural circulation plays an important role in depressurizing the system (e.g., in the use of isolation condensers), then the various modes of two-phase flow natural circulation, including non-condensibles, which may play a significant role in plant response following a small-break LOCA should be demonstrated.

B.14 (F-3.5). All future safety and relief valve challenges and failures should be reported to the NRC. This should include the prompt reporting of failures through Unusual Event Reports and the reporting of challenges in the annual report.

B.15. The B&OTF has recommended substantial changes which will affect system design, system actuation or isolation logic, operator actions, and analysis techniques. GE should review all of the recommendations of the B&OTF and provide an assessment of the collective impact of these recommendations on system safety and reliability.

4.3 Recommended Implementation Schedule

The recommended schedule for the implementation of the aforementioned B&OTF recommendations is provided in Table 4-1.

TABLE 4-1

IMPLEMENTATION OF B&OTF RECOMMENDATIONS FOR GE-DESIGNED BWR PLANTS

Recommendation Designation	Abbreviated Title	Action Required	Implementation Category[a]
A.1	Separation of HPCI and RCIC system initiation levels	(1) Analysis (2) Implementation	S L
A.2	Isolation of isolation condensers on high radiation	Modify isolation circuitry	S
A.3	Spurious isolation of HPCI and RCIC systems	Modify break detection circuitry	S
A.4	Reduction of challenges and failures of relief valves	(1) Feasibility study (2) System modification	S L
A.5	Identify water sources prior to manual actuation of ADS	Modify guidelines and procedures	S
A.6	Report on outage of ECC systems	(1) Submit report (2) Modify Technical Specifications	SS S
A.7	Modification of ADS logic	(1) Feasibility study for staff review (2) Modification to ADS logic	S L
A.8	Interlock on recirculation pump loops	Install interlocks for non-jet pump plants	S
A.9	Loss of service water for Big Rock Point	Verify acceptability of consequences	S
A.10	Restart of core spray and LPCI systems on low level	(1) Preliminary design (2) Modification of restart logic	S L
A.11	Revised emergency procedures	All operators must have read prior to going on duty	SS
A.12	Revise small-break LOCA model for compliance with Appendix K	(1) Revise model (2) Compare with TLTA data	S S
A.13	Plant-specific analyses with revised model	Submit analyses with revised model	L
A.14	No fuel failure requirement for anticipated transients with single failure	Verify compliance with requirement	S

TABLE 4-1 (Continued)

Recommendation Designation	Abbreviated Title	Action Required	Implementation Category[(a)]
A.15	Depressurization with other than ADS	Analyses to support other modes	S
A.16	Two operators in control room	Minimum of two operators in control room	SSS
A.17	Michelson concerns	GE address concerns	SSS
B.1	Automatic switchover of RCIC system suction	(1) Verify procedures (2) Design modification	SS L
B.2	Central water level recording	Installation of recorders	L
B.3	Space cooling for HPCI and RCIC systems	Demonstrate minimum of two-hour capability	L
B.4	Effect of loss of alternating current power on pump seals	Demonstrate adequacy of seal design	L
B.5	Use of RHR for fuel pool cooling	Risk assessment	L
B.6	Common reference for level instruments	Modify scale to obtain common reference	S
B.7	Qualification of accumulators on ADS valves	Show acceptability	L
B.8	Guidelines for symptom-based emergency procedures	Develop new guidelines	LL
B.9	Test program for small-break LOCA model verification	(1) Pretest predictions of first two tests (2) Develop test program (3) Model verification	SSS S LL
B.10	Diverse initiation signal for RCIC system	Upgrade if required	L
B.11	Small-break LOCA on simulators	Upgrade simulator	L
B.12	Use of non-ECC systems in analyses	(1) Review system capability (2) Upgrade if needed	L L
B.13	Performance of isolation condensers with noncondensibles	Demonstrate adequacy	L
B.14	Reporting of failures and challenges to SRVs	Prompt reporting of failures and annual report of challenges	N/A
B.15	Impact of B&OTF recommendations	Assess impact on safety and reliability	L

(a) Category S: Implement by June 30, 1980
Category SS: Implement within 60 days of issuance of this report
Category SSS: Implement within 30 days of issuance of this report
Category L: Implementation by January 1, 1981
Category LL: Implementation by January 1, 1983

APPENDIX A
GE BWR PLANT COMPARISON

1. GENERAL FEATURES

There are several variations of the reactor coolant systems of BWRs. The simplest in concept is a natural circulation system as shown in Figure A-1. In this design, the reactor vessel and its internals comprise the entire reactor coolant system. The flow of the water coolant is caused by density differences within the reactor vessel. The water enters the bottom of the core in liquid form. The heat it receives from the fuel elements that form the nuclear core vaporizes a portion of the coolant, reducing its average density. The mixture of vapor and liquid flows upward into a riser or chimney region. At the top of this region, the vapor continues to rise and flows into steam separators and dryers which remove almost all of the remaining liquid that is entrained in the steam.

The steam produced by the reactor is piped to the turbine where it is used to rotate a generator and produce electricity. The low pressure, low temperature steam leaving the turbine is condensed and returned to the reactor in liquid form.

The liquid that is was separated from the vapor and liquid mixture in the riser or chimney region flows into an annulus between the reactor vessel wall and the shroud that encloses the core. This region is called the downcomer. The condensed water from the turbine (called feedwater) is also returned to this region. The feedwater is distributed circumferentially within the reactor vessel by the feedwater header. The fluid in the downcomer contains little or no vapor and, therefore, has a higher density than the fluid in the core and riser regions. This density difference causes upward flow through the core.

The earliest BWRs (e.g. Humboldt Bay) are of the type described above. Subsequent BWRs use pumped flow in the reactor core to permit higher power levels without large increases in the size of the nuclear core or reactor vessel.

In the first generation of plants that use pumped flow rather than natural circulation flow, all of the liquid from the downcomer region is piped from the reactor vessel to the inlet of a number of centrifugal pumps arranged in parallel. These pumps discharge to the plenum region below the core as illustrated in Figure A-2. As with the natural circulation BWRs, a portion of the total core flow is vaporized; the entrained liquid is removed from the steam; the steam flows to the turbine; and the condensed turbine steam is returned to the reactor.

Most operating BWR plants and those which are the subject of near-term operating license applications use jet pumps in conjunction with a reduced number of centrifugal pumps to provide forced flow through the reactor core. This arrangement is illustrated in Figure A-3. The jet pumps are located in the annulus between the core shroud and the

Figure A-1

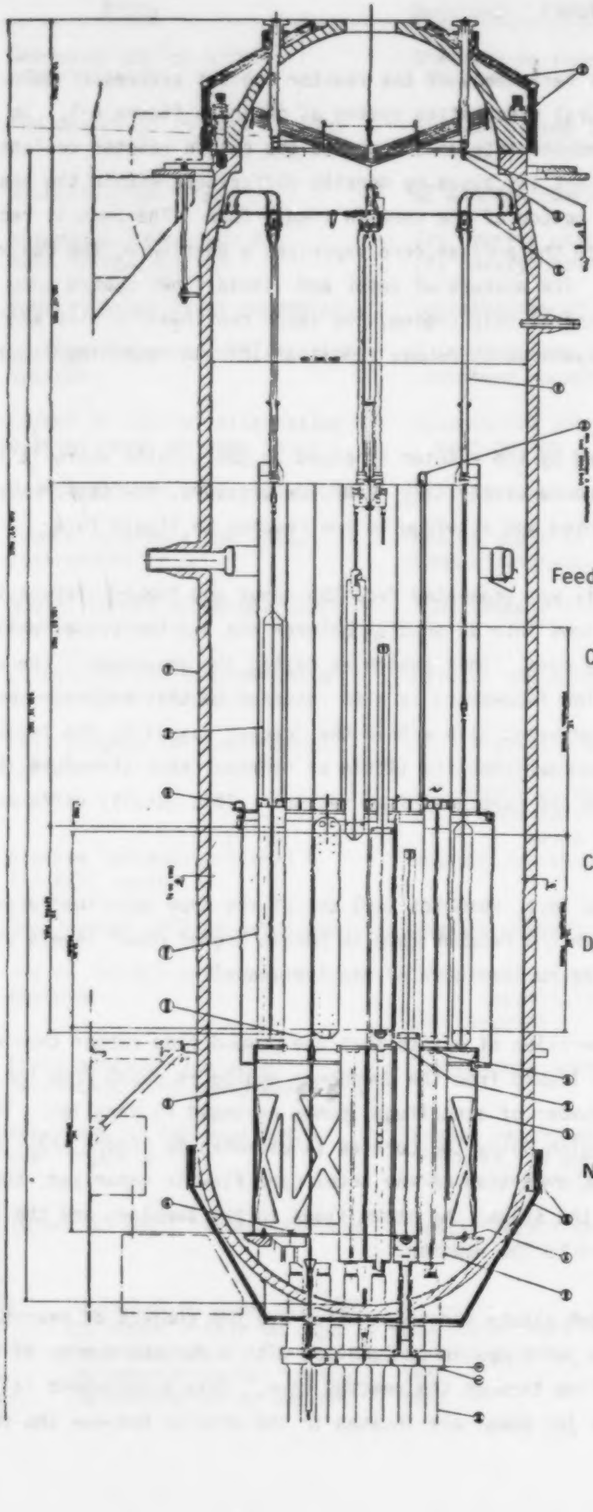

Steam Exit
Feedwater Sparger
Chimney
Core
Downcomer

Figure A-1
Natural Circulation BWR

Figure A-2

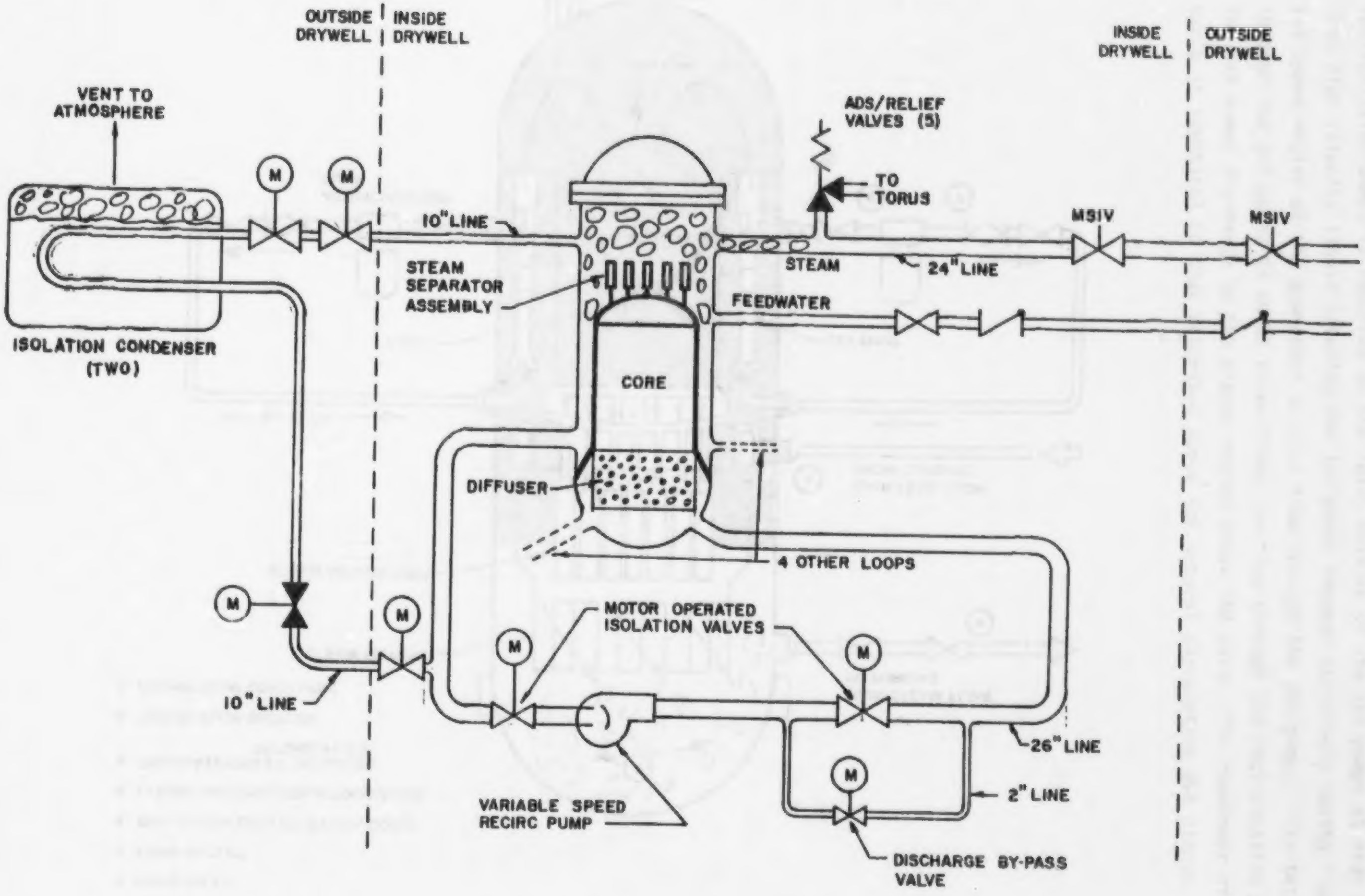

OUTSIDE DRYWELL
INSIDE DRYWELL
VENT TO ATMOSPHERE
M
M
10" LINE
STEAM SEPARATOR ASSEMBLY
ISOLATION CONDENSER (TWO)
CORE
DIFFUSER
M
M
10" LINE
ADS/RELIEF VALVES (5)
TO TORUS
STEAM
24" LINE
FEEDWATER
INSIDE DRYWELL
OUTSIDE DRYWELL
MSIV
MSIV
4 OTHER LOOPS
MOTOR OPERATED ISOLATION VALVES
M
M
M
VARIABLE SPEED RECIRC PUMP
26" LINE
2" LINE
DISCHARGE BY-PASS VALVE

Figure A-2 Non-Jet Pump BWR

Figure A-3

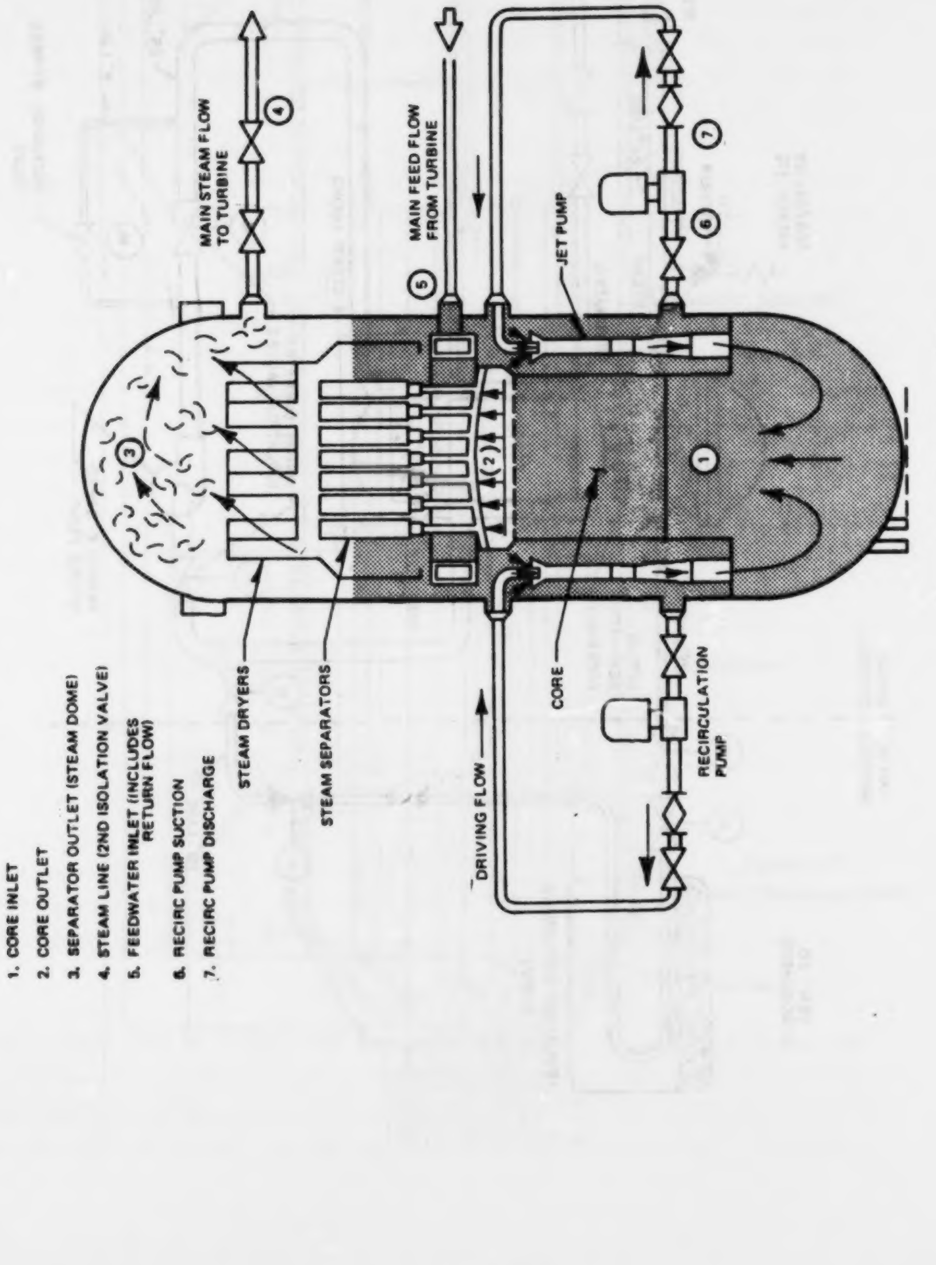

1. CORE INLET
2. CORE OUTLET
3. SEPARATOR OUTLET (STEAM DOME)
4. STEAM LINE (2ND ISOLATION VALVE)
5. FEEDWATER INLET (INCLUDES RETURN FLOW)
6. RECIRC PUMP SUCTION
7. RECIRC PUMP DISCHARGE
MAIN STEAM FLOW TO TURBINE
MAIN FEED FLOW FROM TURBINE
JET PUMP
STEAM DRYERS
STEAM SEPARATORS
DRIVING FLOW
CORE
RECIRCULATION PUMP
1
(2)
3
4
5
6
7

Figure A-3 Jet Pump BWR

reactor vessel wall. In the BWR designs with jet pumps, only about one-third of the liquid in the downcomer region is piped from the reactor vessel to the inlets of the two centrifugal pumps, referred to as recirculation pumps. The discharge from the recirculation pumps is returned to the inlet nozzles of the jet pumps at high velocity. This high velocity liquid entering the jet pumps induces the slowly moving liquid in the upper region of the downcomer to also flow through the jet pumps. The total flow through the jet pumps is about three times the flow through the recirculation pumps. The jet pumps discharge to the plenum region below the core. The remainder of the cycle is identical to that described above for natural circulation BWR plants.

2. DESIGN CHARACTERISTICS OF GE-DESIGNED BWR PLANTS

2.1 Principal Design Characteristics

During normal operation, when normal electrical power for the plant auxiliaries is available, heat is removed from the reactor core through the boiling water- steam turbine-condenser-feedwater cycle. During shutdown, heat is removed through use of the residual heat removal (RHR) system.

For a small-break loss-of-coolant accident (LOCA) or for a loss of feedwater with or without a stuck-open relief valve, high drywell pressure or low reactor vessel water level will actuate the emergency core cooling (ECC) systems to maintain core cooling. Most of the BWR plants that are now operating (BWR/3 and BWR/4 plants) are jet pump plants and have an ECC system consisting of a high pressure coolant injection (HPCI) system, an automatic depressurization system (ADS), a low pressure core spray system, and a low pressure coolant injection (LPCI) system. Another high pressure system, the reactor core isolation cooling (RCIC) system, is available for high pressure injection but is not part of the ECC system because it does not have diverse initiation signals. The ADS system is used to depressurize the primary system in the event that the high pressure systems cannot maintain level. The ADS requires high containment pressure, low reactor water level, and a low pressure emergency core cooling system available for automatic actuation. Other plant designs have other ECC systems which are discussed below. Systems applicable to each plant are summarized in Table A-1.

To assess the adequacy of BWR safety and non-safety systems in mitigating the consequences of loss of feedwater transients and small-break LOCAs, we requested the utilities and GE to provide the additional information related to BWR system design identified in Table A-1. This information, which was provided by the Owners Group in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," in combination with both informal and formal followup information which evolved during the course of our review, provided the basis for our evaluation of the adequacy of these systems. Each of the following sections describes briefly each plant system that we reviewed. In general, these sections address only system inadequacies as determined from our evaluation of NEDO-24708 and supplemental information provided by and discussions with the Owners Group and GE. If the information provided showed that the design and performance of the systems were acceptable, no further discussion is provided.

2.2 Condensate and Feedwater System

The condensate and feedwater system is an integral part of the plant's conventional regenerative steam cycle. This system takes the condensed turbine exhaust steam from the condenser hotwell and purifies, heats, and pumps this condensate to the suction header of the reactor feedwater pumps. The feedwater portion of the system then pumps the condensate back into the reactor vessel at a flow rate sufficient, in conjunction

TABLE A-1
SYSTEMS APPLICABLE TO GE-DESIGNED BWR PLANTS

	BWR Type	RCIC	Isolation Condenser	HPCS	HPCI (4)	LPCS	LPCI	RHR (2)	Shutdown Cooling	Steam Condensate (Hot Standby)	Containment Spray/Supp. Pool Cooling	LPCI Loop Selection Y=Yes; N=No	Feedwater Pump Type M=Motor T=Turbine	Feedwater Coolant Injection (3)	ADS & Pressure Relief Valves	CRD (3)
Dresden 1	1		X			X			X		X		M			X
Humboldt Bay 3	1		X			(5)	X		X		X	N	M	X	X	X
Big Rock Point	1		X			X			X(3)		X		M		X	X
Oyster Creek	2		X			X			X		X		M		X	X
Nine Mile Point	2		X			X			X		X		M/T	X	X	X
Dresden 2	3		X		X	X	X		X		X	Y	M		X	X
Dresden 3	3		X		X	X	X		X		X	Y	M		X	X
Millstone	3		X			X	X		X		X	Y	M	X	X	X
Pilgrim	3	X			X	X		X			X	Y	M		X	X
Monticello	3	X			X	X		X			X	Y	M		X	X
Quad Cities 1	3	X			X	X		X			X	Y	M		X	X
Quad Cities 2	3	X			X	X		X			X	Y	M		X	X

TABLE A-1 (Continued)

	BWR Type	RCIC	Isolation Condenser	HPCS	HPCI	LPCS	LPCI	RHR (2)	Shutdown Cooling	Steam Condensate (Hot Standby)	Containment Spray/Supp. Pool Cooling	LPCI Loop Selection Y=Yes; N=No	Feedwater Pump Type M=Motor T=Turbine	Feedwater Coolant Injection (3)	ADS & Pressure Relief Valves	CRD (3)
Hatch 1	4	X			X	X		X		X	X	N	T		X	X
Hatch 2	4	X			X	X		X		X	X	N	T		X	X
Browns Ferry 1	4	X			X	X		X			X	N	T		X	X
Browns Ferry 2	4	X			X	X		X			X	N	T		X	X
Browns Ferry 3	4	X			X	X		X			X	Y	T		X	X
Vermont Yankee	4	X			X	X		X			X	N	M		X	X
Peach Bottom 2	4	X			X	X		X			X	N	T		X	X
Peach Bottom 3	4	X			X	X		X			X	N	T		X	X
Cooper	4	X			X	X		X		X	X	N	T		X	X
Duane Arnold	4	X			X	X		X		X	X	Y	M		X	X
FitzPatrick	4	X			X	X		X		X	X	N	T		X	X
Brunswick 1	4	X			X	X		X		X	X	N	T		X	X

TABLE A-1 (Continued)

	BWR Type	RCIC	Isolation Condenser	HPCS	HPCI	LPCS	LPCI	RHR (2)	Shutdown Cooling	Steam Condensate (Hot Standby)	Containment Spray/Supp. Pool Cooling	LPCI Loop Selection Y=Yes; N=No	Feedwater Pump Type M=Motor T=Turbine	Feedwater Coolant Injection (3)	ADS & Pressure Relief Valves	CRD (3)
Brunswick 2	4	X			X	X		X		X	X	N	T		X	X
LaSalle 1	5	X		X		X		X		X	X	N	M/T		X	X
LaSalle 2	5	X		X		X		X		X	X	N	M/T		X	X
Zimmer	5	X		X		X		X		X	X	N	T		X	X
Shoreham	4	X			X	X	X	X		X	X	N	T		X	X

with control rod drive return line flow, to equalize the water boiled off from the reactor to drive the turbine- generator and to maintain the required reactor vessel water level.

The condensate and feedwater system is shown in Figure A-4. The main condenser serves as the main heat sink for the plant and provides a volume in which noncondensible gases from the primary steam can collect. The steam from the turbine exhaust is condensed in the condenser and collects in the bottom of the condenser in an area called the hotwell. Various other sources of steam and hot condensate, such as drains, valve leakoffs, and exhausts from steam equipment, are also fed into the condenser. The steam jet air ejectors, which take suction from the main condenser, remove the noncondensible gases and discharge them to the offgas system. In this manner, a vacuum is maintained on the main condenser.

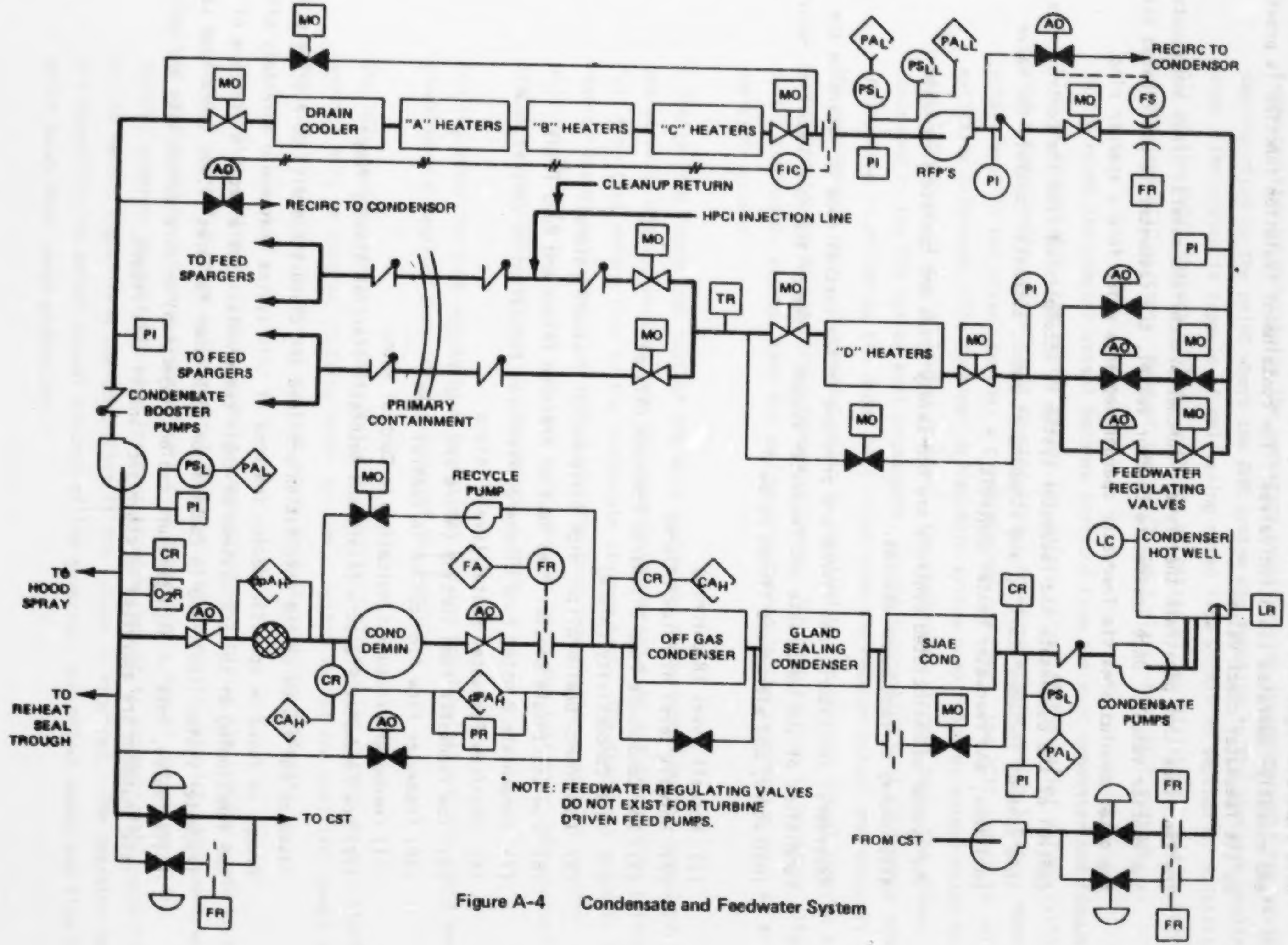
The condensate that is collected in the hotwell is removed by the condensate pumps. These pumps provide a driving force for the condensate which flows through the steam jet air ejector condenser and the gland seal condenser. At this point, the condensate is directed to the condensate demineralizers which, through the processes of ion exchange, remove impurities from the condensate. After the demineralizers, booster pumps maintain the driving force of the condensate flow.

The booster pumps direct the condensate to a series of low pressure feedwater heater strings (designated as A, B, and C on Figure A-4). The term "low pressure" is used because these heaters are fed by extraction steam supplied by the low pressure stages of the low pressure turbines and are in the low pressure portion of the condensate and feedwater system. A bypass is provided around the strings in case one string is isolated to assure that total flow would not be reduced.

The output of the low pressure feedwater heaters is directed to the feedwater pumps. The feedwater pumps give the condensate sufficient pressure to overcome reactor pressure and thereby enable it to be forced into the reactor. The feedwater pumps are either electric-driven or steam-driven pumps or a combination thereof. On the discharge of the feedwater pumps are recirculation lines which feed flow back to the condenser. These lines are used during low feedwater flow conditions to assure a minimum flow of water through the pumps to remove heat added to the condensate by the pump impellers.

The main feedwater coming out of the feedwater pumps passes through full flow regulator valves which are controlled by the reactor level control system. Downstream of the regulator valves are the high pressure feedwater heaters.

The high pressure feedwater heaters (designated as D on Figure A-4) take steam from the high pressure stages of the low pressure turbines. A bypass line around the high pressure heaters is provided in the event one of the heaters fails and has to be isolated.


MO
DRAIN COOLER
"A" HEATERS
"B" HEATERS
"C" HEATERS
MO
PAL
PSL
PSLL
PALL
AO
RECIRC TO CONDENSOR
MO
FS
PI
RFP'S
PI
FR
FIC
AO
RECIRC TO CONDENSOR
CLEANUP RETURN
HPCI INJECTION LINE
TO FEED SPARGERS
TO FEED SPARGERS
MO
MO
TR
MO
"D" HEATERS
MO
PI
PI
AO
AO
AO
MO
MO
MO
PRIMARY CONTAINMENT
PI
CONDENSATE BOOSTER PUMPS
PSL
PAL
PI
CR
O2R
dPAH
MO
RECYCLE PUMP
FA
FR
AO
AO
COND DEMIN
CR
CAH
dPAH
PR
AO
CR
CAH
OFF GAS CONDENSER
GLAND SEALING CONDENSER
SJAE COND
CR
MO
PSL
PAL
PI
FEEDWATER REGULATING VALVES
LC
CONDENSER HOT WELL
LR
CONDENSATE PUMPS
TO HOOD SPRAY
TO REHEAT SEAL TROUGH
TO CST
FR
FROM CST
FR
FR

* NOTE: FEEDWATER REGULATING VALVES DO NOT EXIST FOR TURBINE DRIVEN FEED PUMPS.

Figure A-4 Condensate and Feedwater System

After the heater isolation valves, the piping goes to a common header and then branches into two lines to penetrate the drywell. Outside of the drywell on both branches are motor-operated isolation valves and check valves. At this point, other systems in most plants utilize the feedwater piping as a path for backup sources of water to be injected into the reactor vessel; (i.e., HPCI, reactor water cleanup, and RCIC systems). BWR/5s have separate injection lines for these systems. Inside the drywell are check valves and manually- operated isolation valves. The containment isolation function is provided by the feedwater check valves.

The two lines that penetrate the drywell further branch into several lines and penetrate the reactor vessel. Once inside the reactor vessel, the feedwater is distributed into the outer annulus area via feedwater sparger segments which form a sparger ring.

Control of the condensate and feedwater system is accomplished from the control room. This control includes starting and stopping of pumps, automatic controls for valve positions, and feedwater heater controls.

The system and associated controls are non-safety-grade and operate from normal alternating current power sources.

Recorders, indicators, and alarms are provided in the control room to determine the conditions of the condensate and feedwater system. Some of the more important recorders, indicators, and alarms are listed below:

(1) Hotwell Level (Recorders)
(2) Hotwell Level High/Low (Alarm)
(3) Low Condensate Pump Discharge Pressure (Alarm)
(4) High Conductivity (Alarm)
(5) Condensate Demineralizer High Differential Pressure (Alarm)
(6) Low Condensate Booster Pump Suction Pressure (Alarm and Pump Trip)
(7) Condensate Booster Pump Discharge Pressure (Indication in Control Room)
(8) High/Low Feedwater Heater Levels (Alarm
(9) Low feedwater Pump Suction (Alarm and Pump Trip)
(10) Feedwater Flow (Indication in Control Room),
(11) Feedwater Pressure (Indication in Control Room)
(12) Low Feedwater Pressure (Alarm and Automatic Start of Standby Pump)

Based on our review of the information provided and discussions with GE and the Owners Group, we found no specific design features of this system that would adversely effect the functioning of the ECC systems or their components. The effects of failure of the feedwater system itself and in combination with other failures (i.e., stuck open safety/relief valve, loss of high pressure coolant injection) on core coolability and achieving cold shutdown are addressed in other sections of this report.

2.3 Reactor Core Isolation Cooling System

The RCIC system (Figure A-5), provides sufficient water to the reactor vessel to cool the core and to maintain the reactor in a standby condition if the vessel becomes isolated from the main condenser and experiences a loss of feedwater flow. The system is also designed to permit complete plant shutdown under conditions of loss of normal feedwater flow by maintaining the necessary reactor water inventory until the vessel is depressurized to the point where the RHR system can function in the shutdown cooling mode. The system is capable of delivering rated flow within 30 seconds of initiation. All of the BWR/3 through 5 plants with the exception of the Millstone 1 and Dresden 2/3 plants have RCIC systems. None of the BWR/1 and 2 plants have RCIC systems.

In the event the reactor vessel becomes isolated from the main condenser and feedwater flow is unavailable, the relief valves (or safety valves if the relief valves fail) will automatically maintain the reactor vessel pressure within design limits. When the water level in the vessel reaches a predetermined low level, the RCIC system is automatically initiated. The turbine- driven RCIC system pump supplies makeup water to the vessel from one of the following sources: the condensate storage tank, the steam condensed in the RHR system heat exchangers, or the suppression pool (emergency source). The turbine is driven by the decay heat steam from the reactor vessel and exhausts to the suppression pool. The makeup water is supplied to the reactor vessel through a connection to one of the normal feedwater lines. The pump suction is normally aligned to the condensate storage tank but may be transferred to the suppression pool as an emergency source.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the condensate storage tank and discharging through a full flow test return line to the condensate storage tank. The discharge valve to the reactor vessel head remains closed during the test, and reactor operation remains undisturbed. If the system requires initiation while in the test mode, the control system automatically returns to the operating mode.

Cooling water for pump and turbine operations and for the lube oil and the gland seal condenser is supplied from the discharge of the pump.

The RCIC system operates independently of auxiliary alternating current power, plant service air, or external cooling water systems. System valves and auxiliary pumps are designed to operate by direct current power from the station batteries.

The turbine control system includes a speed governor limiting the turbine speed to its maximum operating speed and a control governor with automatic setpoint adjustment which is positioned by a demand signal from a flow controller. Manual operation of the control governor is possible when in the test mode, but it is automatically repositioned by the demand signal from the controller if the system is required. The operator has the capability to select manual control of the governor, and adjust power and flow to match decay heat steam generation.

Figure A-5

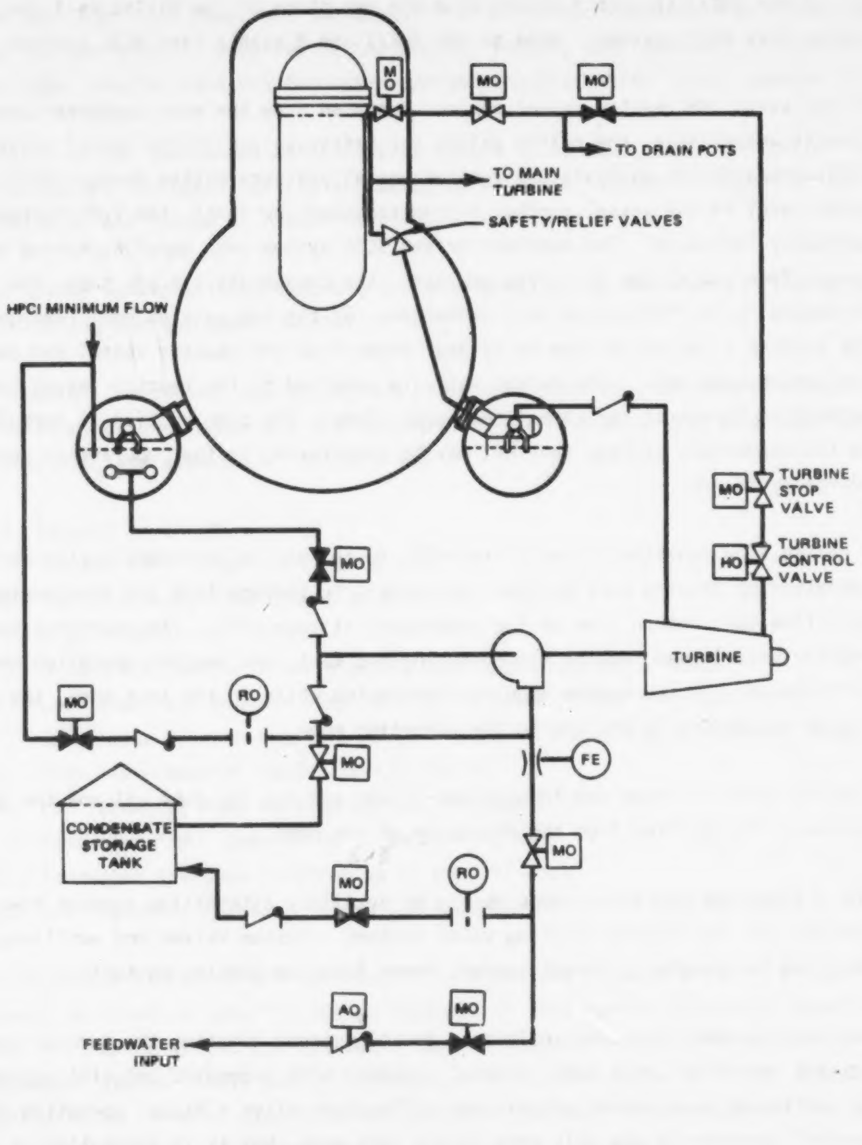

MO
MO
MO
TO DRAIN POTS
TO MAIN TURBINE
SAFETY/RELIEF VALVES
HPCI MINIMUM FLOW
MO
TURBINE STOP VALVE
HO
TURBINE CONTROL VALVE
MO
TURBINE
MO
RO
MO
FE
CONDENSATE STORAGE TANK
MO
MO
RO
AO
MO
FEEDWATER INPUT

Figure A-5 Reactor Core Isolation Cooling System

The turbine and pump automatically shut down upon turbine overspeed, high water level in the reactor vessel, low pump suction pressure, high turbine exhaust pressure, and an automatic isolation signal. The steam supply system to the turbine is automatically isolated upon high pressure drop across in the steam supply line, high area temperature, low reactor pressure, and high pressure between the turbine exhaust rupture diaphragms.

Based on our review of NEDO-24708 and discussions with GE and of the Owners Group, we have identified the following areas where improvements are needed or consideration of improvements has been given:

(1) Currently there is no automatic reset on the RCIC system after it trips on high reactor vessel water level. This requires manual reset by the operator. Depending upon the transient or accident, the operator may have to perform additional actions or be distracted to the extent that he may either forget or delay the reset the RCIC system.

To provide assurance that such an occurrence does not happen, the RCIC systems of all BWRs should be modified to incorporate an automatic reset on high reactor vessel water level. The RCIC system would then restart on loss of level. The operator would then only have to verify proper operation.

(2) GE and the utilities should evaluate the reliability of the components that comprise the RCIC system and make design changes and modifications to those components which would significantly improve overall system reliability. In particular, the circuitry used to detect a broken pipe in the system should be modified to prevent system isolation as a result of the pressure spike which accompanies system actuation.

(3) Currently, with the exception of the Zimmer plant, which has not yet received an operating license, there are no plants which have an automatic switchover of the RCIC system suction from the condensate storage tank to the suppression pool. To eliminate the possibility of an operator error and to minimize the number of actions an operator has to perform, all plants should be modified such that the RCIC system switchover is automatic.

2.4 Isolation Condenser

The isolation condenser provides cooling to the reactor core in the event the reactor becomes isolated from the main condenser by closure of the main steam isolation valves or if main feedwater is unavailable. The isolation condenser is used on BWR/1s, BWR/2s, and some BWR/3 plants.

The isolation condenser system operates by natural circulation without the need for driving power other than the direct current electrical system used to place the system in operation. A typical system consists of one or two condensers and associated piping and valves (Figure A-6). Piping and valves connecting to the reactor vessel allow each isolation condenser to function independently. The isolation condenser consists of two tube bundles immersed in a large water storage tank.

Figure A-6

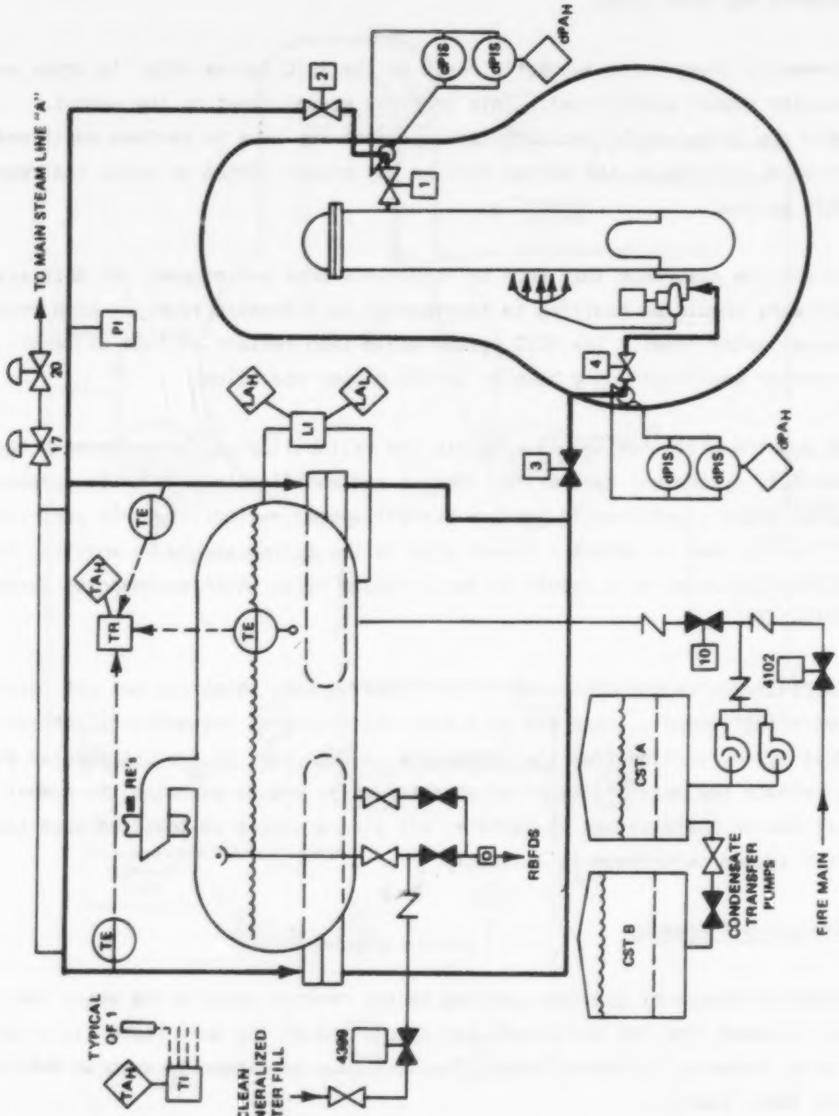

TO MAIN STEAM LINE "A"
PI
20
17
TE
TAH
TR
TE
TE
LAH
LI
LAL
2
1
dPIS
dPIS
dPAH
4
3
dPIS
dPIS
dPAH
10
4102
CST A
CST B
CONDENSATE TRANSFER PUMPS
FIRE MAIN
RBFDS
RE's
TYPICAL OF 1
TAH
TI
CLEAN DEMINERALIZED WATER FILL
4399

Figure A-6 Isolation Condenser System

In the operation of the isolation condenser, steam flows from the reactor through the tubes of the heat exchangers. After condensing it returns by gravity to the reactor. The isolation condensers are located high in the reactor building to facilitate natural circulation. The valves on the steam inlet lines are normally open so that the tube bundles are at reactor pressure. The isolation condenser is placed in operation by opening the closed condensate return valve to the reactor system. This is done automatically on high reactor pressure or it can be done at any time by manual control. The normally-closed valves on the return line are direct current operated and remain available in the event of an alternating current power failure. During operation, the water on the shell side of the condensers will boil and vent to the atmosphere while condensing steam inside the tube bundles.

The isolation valve operation can be tested by remote manual actuation from the control room. Proper operation of all automatic devices in the isolation condenser system can be tested during refueling outages.

Radiation monitors and alarms are provided on the shell vents so that in the event of abnormal radiation levels, the tube side of the heat exchangers can be isolated from the condenser by closing valves.

The water stored in the shell of the isolation condensers can be supplemented by makeup from storage tanks or a pond, pumped by either the condensate transfer pumps or by either of the two diesel-driven fire pumps. Demineralized water can be supplied to the isolation condenser shells for fill and normal makeup.

Leaks in the isolation condenser system are detected by sets of two different pressure measurements located in the first elbow of each system line leaving the reactor vessel and in each return line at the elbow closest to the reactor vessel.

Plants with isolation condensers require that makeup water to the reactor vessel be provided to account for leakage and blowdown through the safety/relief valves when the isolation condenser is in operation. This can be provided by the high pressure injection system, feedwater coolant injection system, or the control rod drive system, depending upon the plant.

In the May 2, 1979 loss of feedwater event at the Oyster Creek plant, a standing order required the operator to isolate the two recirculation loops into which the isolation condensers discharge. This was presumably to prevent a spurious isolation of the isolation condensers due to a high differential pressure across the sensor used to detect a break in the isolation condenser piping. Test data show that the recirculation pumps must be tripped to prevent the isolation signal but the recirculation loops need not be isolated.

Because the recirculation pumps trip on low level and the recirculation loops need not be isolated, no operator action is required for isolation condenser operation under conditions where automatic operation for transient mitigation has been assumed. Further, the operator should not routinely isolate the recirculation loops with the isolation condensers unless stable conditions have been established and adequate vessel water level has been verified.

Based on our review of NEDO-24708 and discussions with GE and the Owners Group, we have identified the following areas where improvements are needed or consideration of improvements has been given:

The isolation condensers have radiation monitors on the atmospheric vent line located on the shell side. These monitors alarm in the control room on high activity levels and are indicative of primary to secondary side leakage. It is our position that on a high radiation level, the tube side of the isolation condensers should automatically isolate so unacceptable doses to the atmosphere do not occur. Isolation of the condenser may also require operator action to provide other means of cooling the reactor. In addition, the operator action may vary depending upon the time during the event when isolation occurs.* Therefore, specific provisions should be incorporated into the appropriate plant emergency procedures to account for condenser isolation.

In response to a question pertaining to auxiliary systems required for operation of the isolation condenser, it was noted that makeup water to the shell side of the condenser was required. This was further clarified to be a minimum of 40 minutes in a response from the Owners Group. We find it acceptable to assume the operator could take action to provide makeup within this time frame.

No other features of the isolation condenser system design were found unacceptable or in need of improvement.

2.5 High Pressure Coolant Injection System

The HPCI system is designed to assure adequate coolant inventory in the reactor vessel for a spectrum of design basis LOCA conditions that do not result in a rapid depressurzation of the reactor vessel (small breaks). The HPCI system permits the reactor to be depressurized through the addition of cold water and continues to operate until the reactor vessel pressure is below that at which the LPCI and core spray systems can be operated.

The HPCI system shown in Figure A-7 consists of a steam turbine driving a main pump and a booster pump through a reduction gear, valves, high-pressure piping, water sources, and instrumentation designed to pump water into the reactor vessel under certain LOCA conditions associated with high reactor pressure. The turbine-driven pump unit is usually located within the reactor building.

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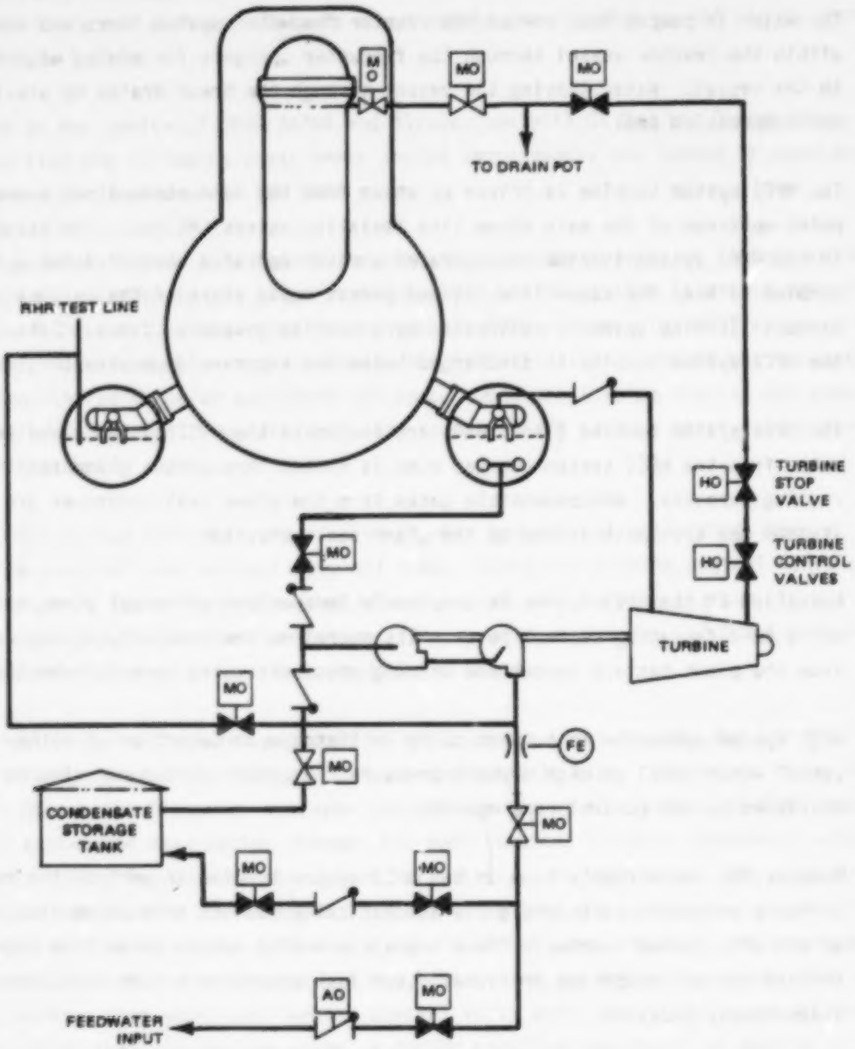
* The need for and type of operator action could be based on water level in the reactor vessel. If isolation occurs early in the event, it may not be possible to maintain water level without depressurization, whereas, if isolation occurs later, the control rod drive system may provide adequate makeup without depressurization.

Figure A-7



M O
MO
MO
TO DRAIN POT
RHR TEST LINE
HO
TURBINE STOP VALVE
HO
TURBINE CONTROL VALVES
MO
TURBINE
MO
MO
FE
CONDENSATE STORAGE TANK
MO
MO
MO
AO
MO
FEEDWATER INPUT

Figure A-7 High Pressure Coolant Injection System

The HPCI system is designed to pump water into the reactor vessel within a reactor pressure range of about 1150 psig to 150 psig. Two sources of water are available. Water will be supplied initially from a condensate storage tank. When the water in the condensate storage tank has fallen to a predetermined level or the water in the suppression pool is above a predetermined level, the pump suction supply will be automatically transferred to the suppression pool. Approximately 100,000 gallons of water are held in reserve in a condensate storage tank as a supply for the HPCI system.

The water is pumped into one of the reactor feedwater system lines and distributed within the reactor vessel through the feedwater spargers for mixing with the hot water in the vessel. Water leaving the vessel through the break drains by gravity back to the suppression pool.

The HPCI system turbine is driven by steam from the main steam lines extracted from a point upstream of the main steam line isolation valves (MSIVs). The steam supply line to the HPCI system turbine incorporates a motor-operated shutoff valve upstream of the turbine to keep the steam line hot and permit rapid start of the unit without turbine warmup. Turbine speed is controlled by a turbine governor system. Exhaust steam from the HPCI system turbine is discharged below the suppression pool water level.

The HPCI system turbine gland seals are vented to the HPCI system gland seal condenser. Water from the HPCI system booster pump is routed through the gland seal condenser for cooling purposes. Noncondensible gases from the gland seal condenser are pumped to the standby gas treatment system by the gland seal exhauster.

Operation of the HPCI system is completely independent of normal plant on-site and off-site alternating current power. Its operation requires only direct current power from the plant battery system and driving steam extracted from the reactor.

HPIC system operation is automatically initiated upon detection of either low reactor vessel water level or high drywell pressure. The HPCI system can also be manually initiated by the control room operator.

Because the steam supply line to the HPCI system turbine is part of the reactor coolant pressure boundary, certain signals automatically isolate this steam line causing shutdown of the HPCI system turbine. These signals are HPIC system steam line high flow, high turbine exhaust diaphragm pressure, steam leak detection system initiation, and low steam supply pressure.

The HPCI system turbine also can be shut down directly by a number of signals. These signals are high turbine exhaust pressure, low pump suction pressure, high reactor vessel water level, turbine overspeed, any of the isolation signals given above, and a manual pushbutton signal.

The HPCI system is provided with full flow test capabilities. Water is taken from the condensate storage tank and pumped through a line back to the condensate storage tank.

The injection valves which permit the water to go to the reactor vessel under accident conditions remain closed during the full flow test. Should an accident signal be received while the full flow test is being performed, the system will to supply water to the reactor vessel.

The Dresden 1, Humboldt Bay, Nine Mile Point 1, and Millstone 1 plants have a feedwater coolant injection (FWCI) system instead of a HPCI system. This system provides essentially the same function as the HPCI system by supplying emergency power to part of the feedwater systems. This is a non-safety grade system on all plants except the Millstone 1 plant.

Based on our review of NEDO-24708 and discussions with GE and the Owners Group, we identified the following areas where design improvements are needed or consideration of the need for improvements has been given:

As is seen in Figure A-7, the HPCI system turbine stop valves and control valves are closed in addition to the steam shutoff valve when the system is not in operation whereas these valves are normally open on the RCIC system. The HPCI system turbine stop valves and turbine control valves are hydraulically- operated and are opened on system initiation by an auxiliary oil pump. Once the turbine starts, oil pressure is supplied from an oil pump driven by the turbine shaft to keep these valves open and to control turbine speed.

The RCIC system turbine control valve is also hydraulically operated, however, the RCIC system does not have an auxiliary oil pump. Since the turbine control valve receives oil pressure from the turbine control oil system upon turbine startup, it has to be normally open to start up the system. The turbine stop valve, although motor-operated, is also left normally-open for rapid system startup.

In reviewing the failures reported in the Licensee Event Reports for the HPCI system, the frequency of failures appears to be inordinately high. Therefore it is recommended that GE and the licensees evaluate the reliability of the components that comprise the HPCI system and make design changes and modifications to those components which would significantly improve overall system reliability. In particular, the circuitry which is used to detect a broken steam line and to isolate the system must be modified to prevent isolation of the system as a result of the pressure spike which accompanies system actuation. For example, if the reliance on the hydraulic system used to open the turbine stop valve and turbine control valve were identified as one of the HPCI subsystems that was failure prone, a design modification should be made to eliminate the dependence of these valves on this subsystem.

No other features of the HPCI system other than those identified above were found unacceptable.

2.6 Low Pressure Coolant Injection System

Low pressure coolant injection is an operating mode of the RHR system. In the case of low water level (Level 1) in the reactor or high pressure in the containment drywell, the LPCI system pumps water into the reactor pressure vessel. LPCI system operation provides protection to the core for the case of a large break in the reactor coolant system when the feedwater pumps, the control rod drive pumps, and the high pressure systems are unable to maintain water level in the reactor pressure vessel. Protection by the LPCI system also extends to small breaks for which the feedwater pumps, control rod drive pumps, and high pressure systems are unable to maintain water level and the ADS has operated to lower the reactor vessel pressure so that the LPCI and core spray systems can provide core cooling. A schematic of a typical LPCI system is given in Figure A-8.

The isolation valves for the LPCI system are automatically opened when the vessel pressure decreases to approximately 500 psig but injection flow does not occur until the differential pressure across the check valves permits. This ranges from approximately 200 psig to 300 psig, depending upon the particular plant.

During LPCI system operation, the RHR system pumps take suction from the supression pool and discharge to the reactor pressure vessel. For the BWR/3 and BWR/4 plants, LPCI system flow enters the vessel through the recirculation loop discharge lines. For the BWR/5 plants, LPCI system flow is injected into the core bypass region inside the core shroud. LPCI system operation uses four pumps and two loops although only three out of four pumps are needed for LPCI system cooling.

Power for the LPCI system pumps is supplied from alternating current buses that are powered by standby sources. Each pump is powered from a separate bus. Motive power for the automatic valves comes from one of the lines that powers the pumps for that loop. Control power for the LPCI system components comes from the direct current buses. Typically, the LPCI system cannot be diverted for five minutes. This protects against premature diversion of the LPCI system flow to containment spray.

Some of the same components of the RHR system used for the LPCI system are also used for containment cooling. However, the valves that divert water for containment cooling are signaled closed on receipt of LPCI system initiation signal. These valves cannot be opened by manual action unless two conditions exist. The accident initiation signal, indicating the need for containment cooling, must be present, and the water level inside the core shroud must be above the level equivalent to two-thirds the core height. A keylock switch in the main control room allows manual override of the two-thirds core height and accident initiation signal permissives for the containment cooling valves.

The RHR system pumps and heat exchanges may occasionally be called upon to supply fuel pool cooling. We believe this to be a needless diversion of safety systems. This function combined with the RHR system's function as a shutdown cooling system, LPCI system, and containment cooling system places too large a burden on the system. We

Figure A-8

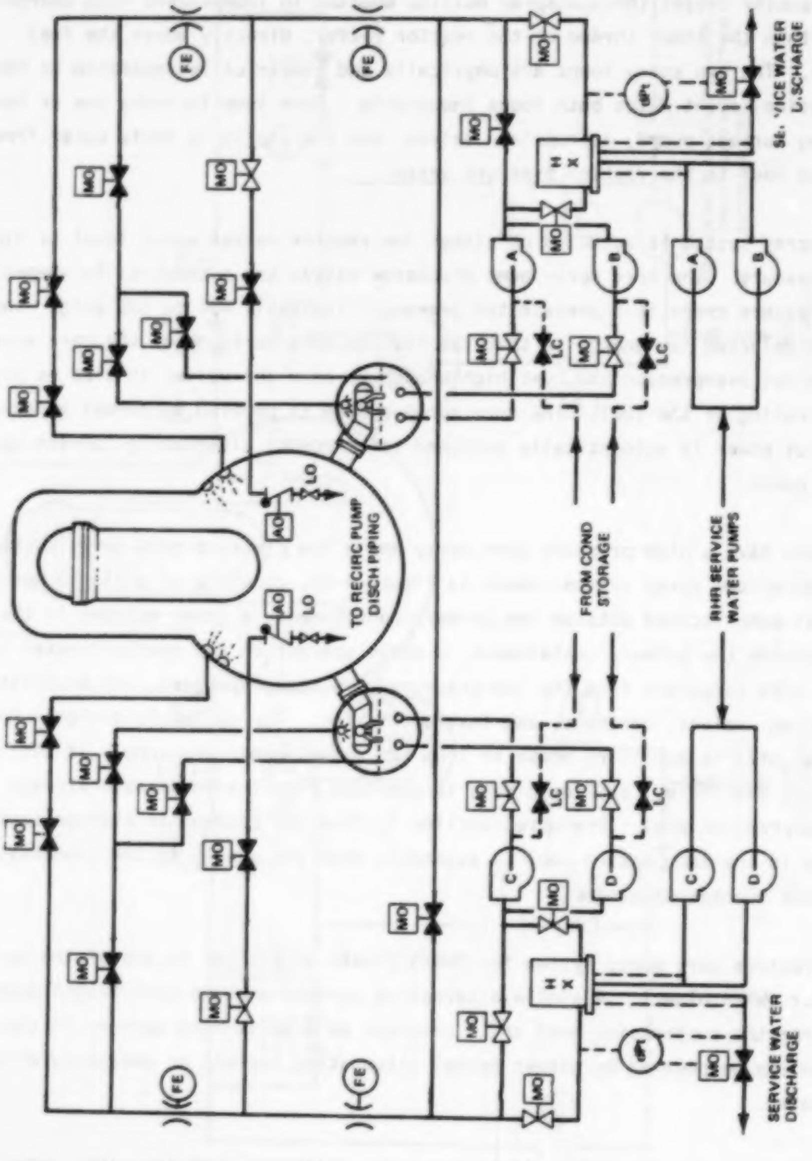

TO RECIRC PUMP DISCH PIPING
MO
FE
AO
LO
LC
HX
A
B
C
D
dP
FROM COND STORAGE
RHR SERVICE WATER PUMPS
SERVICE WATER DISCHARGE
SE. VICE WATER D.SCHARGE

Figure A-8 Low Pressure Coolant Injection System and Containment Spray/Cooling System believe that the RHR system should be dedicated to shutdown cooling and its safety functions of low pressure coolant injection and containment cooling.

2.7 Core Spray System

Typically, the core spray system consists of two independent subsystems with full-capacity capability. The core spray system is shown schematically in Figure A-9. For BWR/2 through BWR/4 plants, the core spray system pumps water from the suppression pool into the reactor vessel through spray nozzles mounted in independent ring spargers located within the inner shroud of the reactor vessel, directly above the fuel assemblies. The two spray loops are physically and electrically separated so that no single physical event makes both loops inoperable. Each loop includes one or two alternating current pumps, appropriate valves, and the piping to route water from the suppression pool to the reactor pressure vessel.

The core spray system is actuated on either low reactor vessel water level or high drywell pressure. The core spray pump discharge valves are automatically opened when reactor pressure drops to a preselected pressure, typically 400 to 500 psig. The setting is selected low enough so that the low pressure portions of the core spray system are not overpressurized, yet high enough to open the valves in time to provide adequate cooling of the fuel. The core spray system is powered by normal alternating current, but power is automatically switched to emergency alternating current upon loss of normal power.

BWR/5 plants have a high pressure core spray and a low pressure core spray system. The high pressure core spray system, shown in Figure A-10, consists of a single motor-driven centrifugal pump located outside the primary containment, a spray sparger in the reactor located outside the primary containment, a spray sparger in the reactor vessel located above the core (separate from the low pressure core spray sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from normal offsite auxiliary power or from its diesel-generator supply if offsite power is not available. Suction piping is provided from the condensate storage tank and the suppression pool. Preferred suction is from the condensate storage tank and switchover to the suppression pool is automatic when the supply in the condensate storage tank becomes exhausted.

The low pressure core spray system for BWR/5 plants is similar to one of the spray systems for BWR/4 plants. A single alternating current-powered centrifugal pump takes suction from the suppression pool and discharges to a split-ring sparger in the vessel. The system may be powered by either normal alternating current or emergency alternating current power.

The spray systems for the BWR/1 plants are quite different from the other spray systems. They are shown schematically in Figures A-11 through A-13. For the Big Rock Point plant, there are two core spray pumps and two fire pumps which feed a ring sparger and a top head nozzle. One fire pump is diesel-driven and one fire pump is motor-driven.

Figure A-9

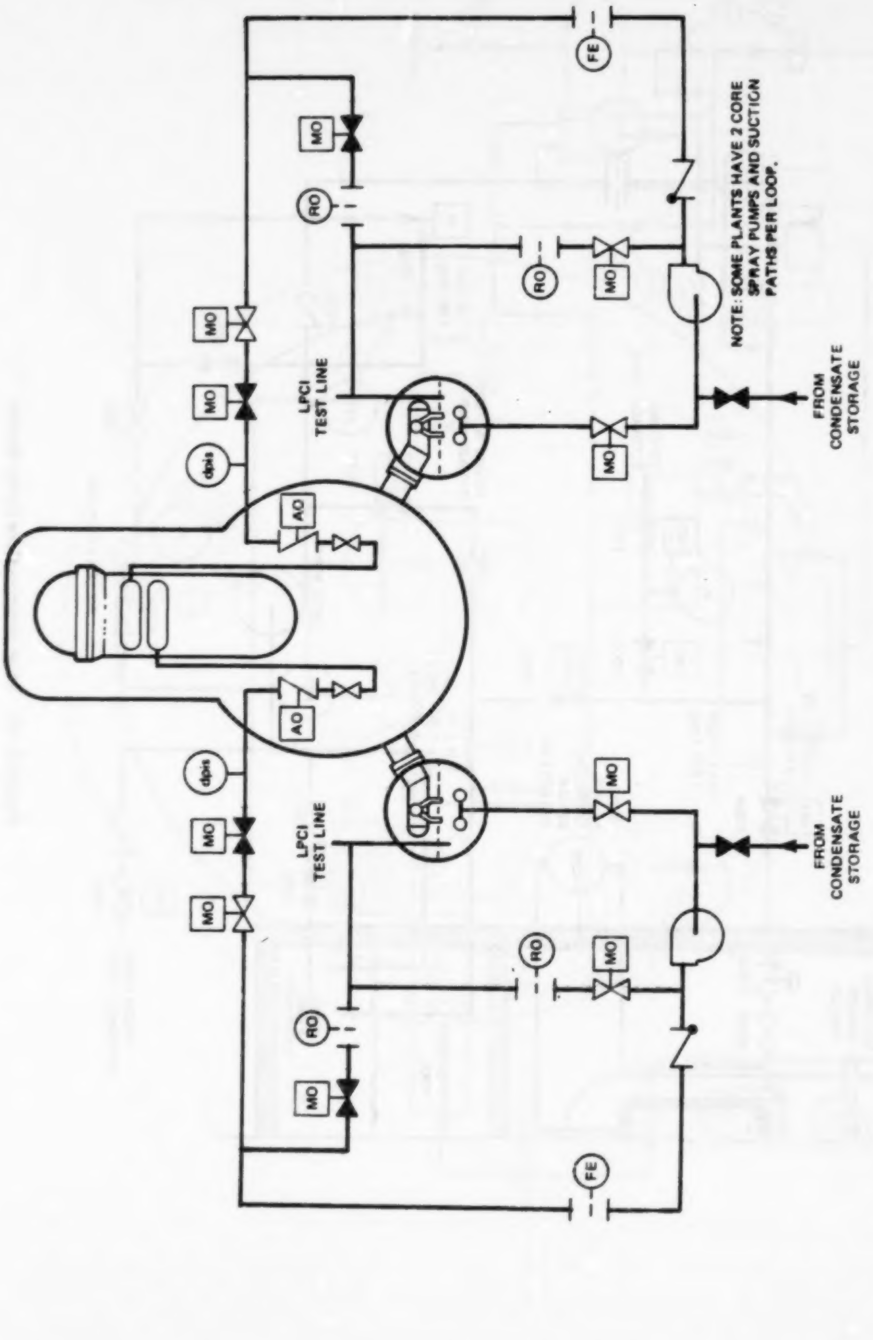
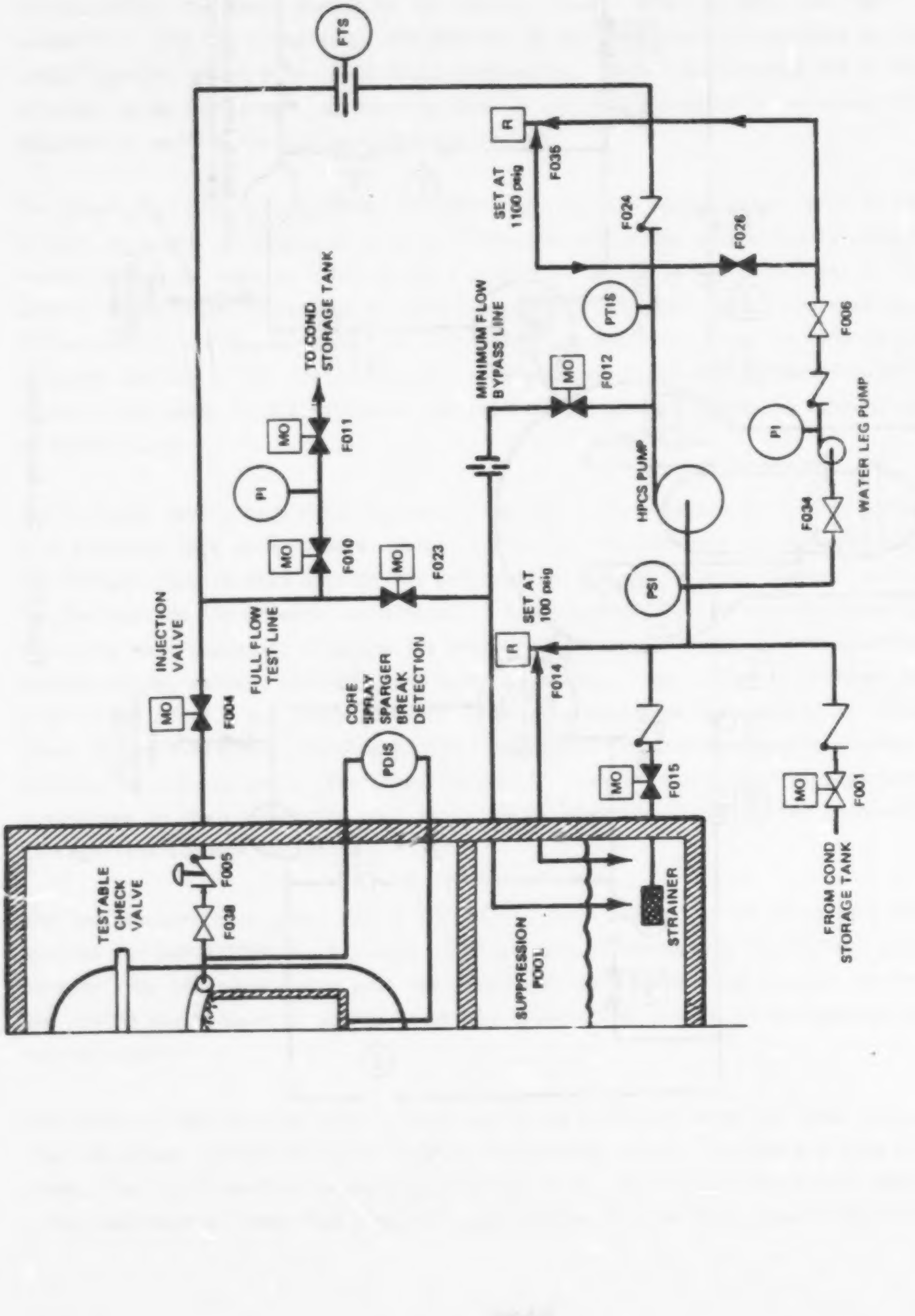

MO
RO
FE
MO
RO
MO
MO
dpis
AO
AO
dpis
MO
MO
LPCI TEST LINE
LPCI TEST LINE
MO
MO
NOTE: SOME PLANTS HAVE 2 CORE SPRAY PUMPS AND SUCTION PATHS PER LOOP.
FROM CONDENSATE STORAGE
MO
FROM CONDENSATE STORAGE
RO
MO
RO
MO
FE

Figure A-9 Core Spray System

Figure A-10



TESTABLE CHECK VALVE
F038
F005
INJECTION VALVE
MO
F004
FULL FLOW TEST LINE
CORE SPRAY SPARGER BREAK DETECTION
PDIS
SUPPRESSION POOL
STRAINER
FROM COND STORAGE TANK
MO
F001
MO
F015
R
F014
SET AT 100 psig
MO
F023
MO
F010
PI
MO
F011
TO COND STORAGE TANK
FTS
MINIMUM FLOW BYPASS LINE
MO
F012
HPCS PUMP
PSI
PTIS
F024
F026
F006
SET AT 1100 psig
F035
R
PI
WATER LEG PUMP
F034

Figure A-10 High Pressure Core Spray System

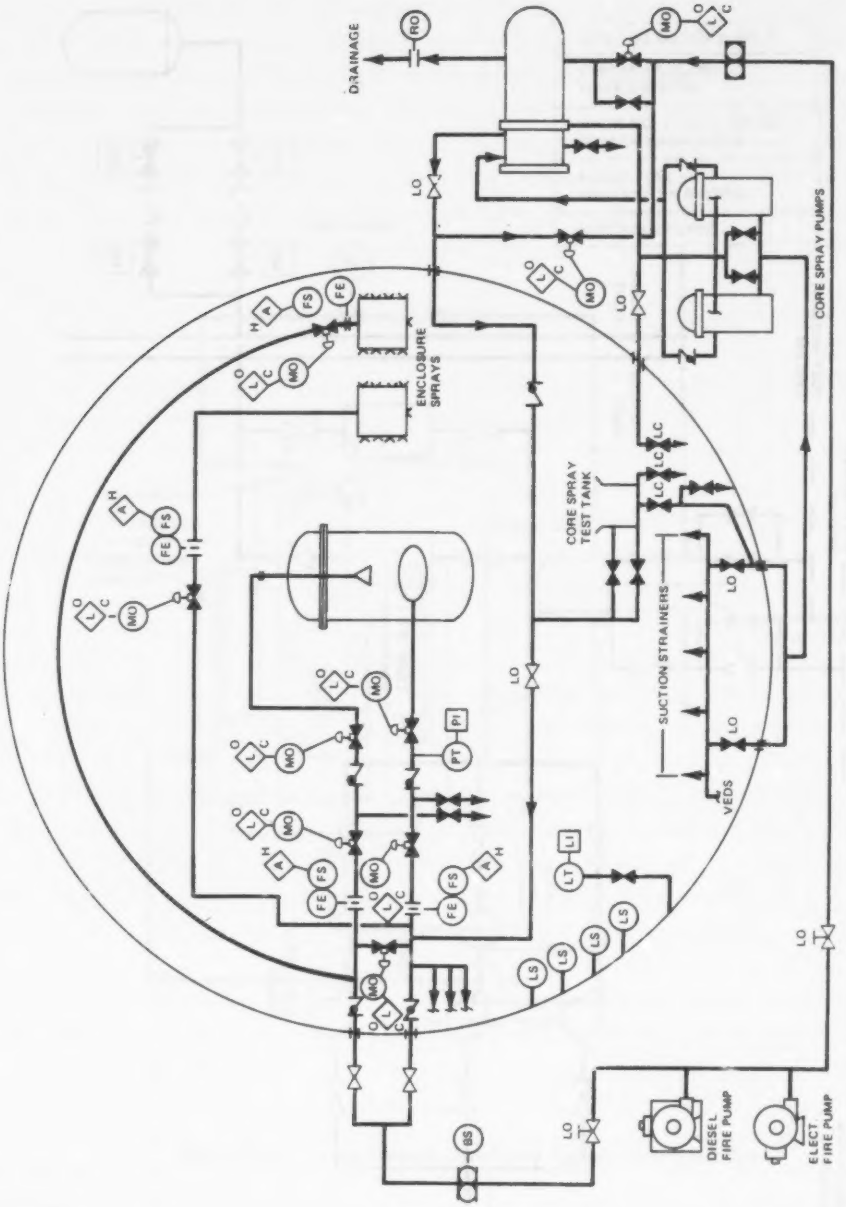

DRAINAGE
RO
MO
O
L
C
LO
ENCLOSURE SPRAYS
FE
FS
A
H
CORE SPRAY TEST TANK
LC
SUCTION STRAINERS
VEDS
CORE SPRAY PUMPS
PT
PI
LT
LI
LS
BS
DIESEL FIRE PUMP
ELECT FIRE PUMP

Figure A-11 Enclosure and Core Spray System (Big Rock Point)

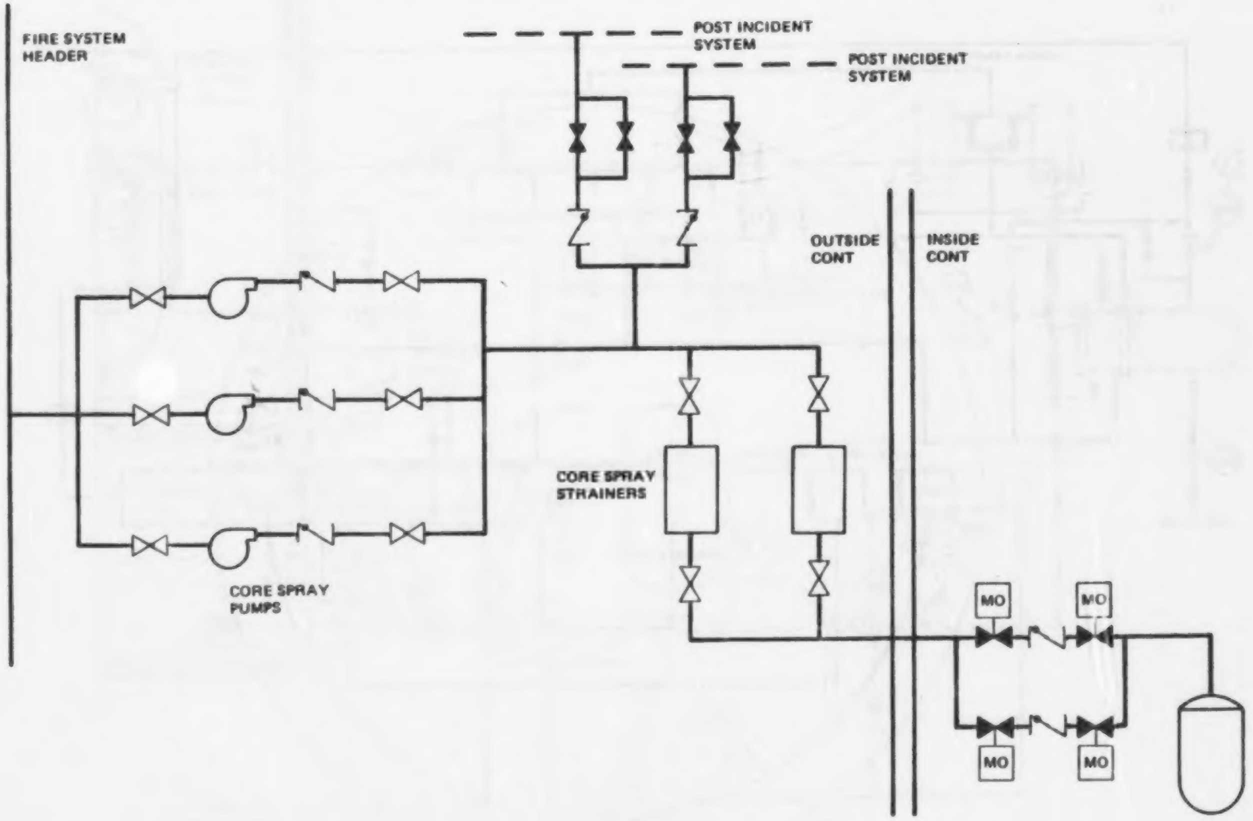

FIRE SYSTEM HEADER
POST INCIDENT SYSTEM
POST INCIDENT SYSTEM
OUTSIDE CONT
INSIDE CONT
CORE SPRAY STRAINERS
CORE SPRAY PUMPS
MO
MO
MO
MO

Figure A-12 Core Spray System (Dresden 1)

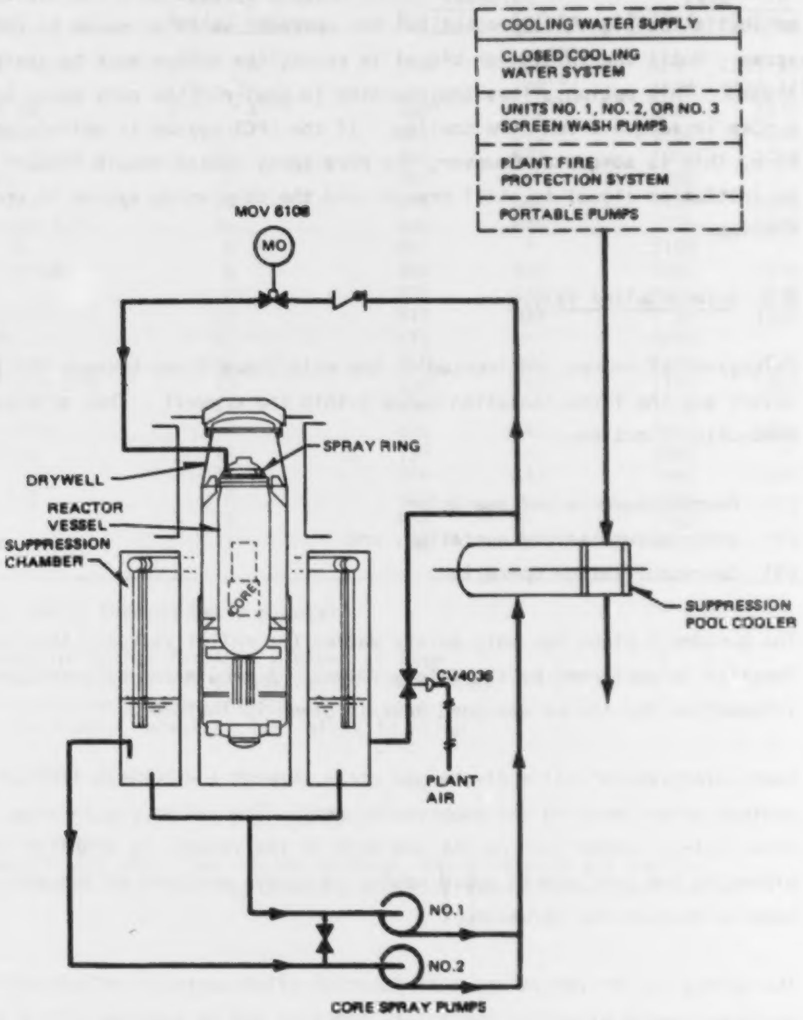

COOLING WATER SUPPLY
CLOSED COOLING WATER SYSTEM
UNITS NO. 1, NO. 2, OR NO. 3 SCREEN WASH PUMPS
PLANT FIRE PROTECTION SYSTEM
PORTABLE PUMPS
MOV 6108
MO
SPRAY RING
DRYWELL
REACTOR VESSEL
SUPPRESSION CHAMBER
CORE
SUPPRESSION POOL COOLER
CV4036
PLANT AIR
NO.1
NO.2
CORE SPRAY PUMPS

Figure A-13 Low Pressure Core Spray System (Humboldt Bay)

The Dresden 1 spray system consists of three centrifugal pumps that can be powered by normal auxiliary power or the standby ac power system. The Dresden 1 spray system delivers water directly to each fuel bundle. The Humboldt Bay plant spray system consists of two core spray pumps which take suction from the suppression pool and feed a single spray ring above the core.

Typically, the core spray pumps can be stopped by placing a keylock switch in stop if an initiation signal is present but the operator wants or needs to terminate core spray. Until the initiation signal is reset, the system must be started manually if needed. This option allows the operator to shut off the core spray system if the LPCI system is adequate for core cooling. If the LPCI system is delivering flow to the core, this is adequate; however, the core spray system should restart automatically if an initiation signal is still present and the core spray system is required for adequate cooling.

2.8 Safety/Relief Valves

Safety/relief valves are located on the main steam lines between the reactor pressure vessel and the first isolation valve within the drywell. They provide three main protection functions:

(1) Overpressure-relief operation,
(2) Overpressure-safety operation, and
(3) Depressurization operation.

The Dresden 1 plant has only safety valves (no relief valves), thus only the second function is performed by its safety valves. A tabulation of safety/relief valve design information for the GE-designed BWRs is given in Table A-2.

Each safety/relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The valves are located on the main steam line piping, rather than on the top head of the vessel, to simplify the discharge piping to the pool and to avoid having to remove sections of the piping when the vessel head is removed for refueling.

The safety/relief valves are dual-function pilot-operated relief valves. They use a spring-actuated pilot for the safety function and an external air-diaphragm-actuated pilot for the relief function.

The operating history of the safety/relief valves has been poor (see Section 2. of Appendix B to this report). A new pilot design is used in some plants but the operational history is too brief to evaluate the effectiveness of this design change. Another way of improving the performance of the valves is to reduce the number of challenges to the valves. This may be done by lowering the setpoint pressure for main steam line isolation or by increasing the high steam flow setpoint for main steam line isolation. The feasibility of changing these setpoints should be investigated and the setpoints changed if no additional problems are created by the change.

Table A-2

SAFETY/RELIEF VALVE DESIGN INFORMATION

Plant	Total Number of Safety and/or Relief Valves	Capacity (each) Klb/hr at Lowest Setpoint		Lowest Setpoint psig	
		Relief	Safety	Relief	Safety
Big Rock Point	8(5) - 6(6)	518(5)	240(6)	N/A	1535-1585
Dresden 1	10 - 2	-	200(6)	1070	1210-1250
Humboldt Bay	2(5) - 4(6)	400(5)	400(6)	N/A	1220
Oyster Creek	21	561	630	1050	1212
Nine Mile Point 1	22	600	633	1090	1218
Millstone	6	800	-	1095	-
Dresden 2/3	13	540	640	1115	1240
Quad Cities 1/2	13	540	640	1115	1240
Monticello	8	840	-	1108	-
Vermont Yankee	6	800	925	1080	1240
Pilgrim	6	800	640	1095	1240
Peach Bottom 2/3	13	819	925	1105	1230
Hatch 1/2	11	870	-	1090	-
Browns Ferry 1	11	850	940	1105	1250
Browns Ferry 2/3	13	850	940	1105	1250
Brunswick 1/2	11	830	-	1105	-
Duane Arnold	8	830	642	1080	1240
FitzPatrick	11	798	-	1090	-
Cooper	11	800	642	1080	1240
LaSalle 1/2	18	850	-	1076	-
Zimmer	13	865	-	1150	-
Shoreham	11	889	-	1115	-

Notes for BWR/2 through BWR/5 plants:

(1) Number of cycles for ADS: minimum of five
(2) Number of cycles for safety/relief: unlimited
(3) Alternate air supply for ADS
(4) No air supply necessary for safety function

Notes for BWR/1 plants:

(5) Automatic depressurization system
(6) Spring safety
(7) Humboldt Bay ADS: two cycles minimum, has alternate air supply
(8) Big Rock Point: cycling capacity and alternate air not applicable

Position indication on the safety/relief valves is indirect. Although the temperature of the discharge piping is also monitored as an indication of valve position, the temperature indication is useless if the valve has been cycled or if the valve leaks. A direct indication of valve indication or a positive indication in the control room of valve flow should be provided.

2.9 Automatic Depressurization System

The ADS serves as a backup to the HPCI system. It performs the function of vessel depressurization when required for small line breaks at high reactor pressures. This allows the core spray and LPCI systems to operate and provide adequate core cooling. With the exception of the Dresden 1 plant, all BWR plants have ADSs. Vessel design permits one or two ADS actuations during the 40-year life of the plant; therefore, ADS actuation is used only when the high pressure systems cannot maintain level.

The ADS consists of dual-function safety/relief valves (each with an air supply), an accumulator, a discharge line to the suppression pool (including vacuum breakers), and associated initiation and leakage detection systems.

The safety/relief valves are located on each of the main steam lines between the reactor vessel and the main steam line isolation valves (MSIVs). Each of the safety/relief valves discharge through a separate line to a point below the water level of the suppression pool. The discharge lines are equipped with vacuum-relief valves (vacuum breakers) to prevent drawing water up into the line due to steam condensation following safety/relief valve operation.

The safety/relief valves consist of two principal sections - a pilot valve section and a main valve section. These two sections are directly coupled to comprise a self-actuated safety/relief valve. The pilot valve section is the pressure sensing and control element and the main valve is a hydraulically (primary steam) actuated follower valve which provides the pressure relief function.

The ADS control system operates a solenoid-actuated air valve that allows plant air into the pilot valve to open the safety/relief valve. An accumulator is provided for operation of the safety/relief valve in the event the plant air system fails. The accumulator is designed to open the safety/relief valve and keep the valve open long enough to depressurize the primary system.

The ADS receives electrical power from the plant direct current system.

The safety/relief valves designated for the ADS automatically open when all of the following conditions are met: (1) high drywell pressure, (2) low vessel water level, and (3) pump discharge pressure as sensed by either the LPCI or core spray system pumps. If these conditions are met, a time delay of 105 to 120 seconds is imposed before the solenoid control valves are energized from 125-volt direct current power and the safety/relief valves open. The valves then remain open until reactor pressure is reduced to approximately 50 psig. If during the delay period the operator should determine that the valves did not open, solenoid valve actuation can be prevented by resetting the delay timer. Even after initiation, pushing the timer reset will interrupt the ADS initiation signal and restart the timer. After the prescribed delay, if all initiating conditions remain, the ADS signal would again be applied and the valves would open.

The ADS valves are controlled by dual position switches in the control room. In the automatic position, the valves will open either on an ADS signal or an overpressure (relief or safety mode) condition. The valves open and remain open as long as the switch is in this position.

Based on our review of NEDO-24708 and discussions with GE and the Owners Group, we have identified the following areas where improvements are needed or consideration of improvements has been given:

(1) There are no interlocks on the ADS when the switch is in the open position as there are when the switch is in the automatic position. Therefore, during a transient or accident, the operator could inadvertently depressurize the reactor without having the low pressure core spray or LPCI systems operational. We have evaluated this scenario and have determined there are two potential courses of action to prevent this occurrence: (a) installation of a permissive interlock that requires either a low pressure core spray or LPCI system pump to be in operation for the ADS valves to open when the switch is in the open position, or (b) require that the emergency procedures include verification that a source of water for cooling the reactor is operational prior to placing the ADS switch in the open position. Installation of a permissive interlock limits the sources of cooling water and, although the probability of losing both the low pressure core spray and LPCI systems (in addition to the high pressure coolant injection and RCIC systems) is remote, alternate sources of cooling, if available, could not be utilized. Therefore, we recommend that emergency procedures include operational verification that a source of cooling water be available prior to manually depressurizing the reactor vessel using the ADS, and that available alternate water sources be identified in the procedures and reference other applicable procedures for startup and operation of these sources.

(2) Position indication of all ADS valves on all BWR plants is indirect. Since these valves also perform a safety and relief function, the requirements for compliance with short-term recommendation 2.1.3a of NUREG-0578 related to direct position indication for relief and safety valves are addressed in Section 2.8 of this report.

(3) In the analyses of small-break LOCAs and loss of feedwater events presented in NEDO-24708, it has been shown that for steam line breaks outside containment and for a loss of feedwater with a stuck-open safety/relief valve with only the low pressure ECC systems available, operator action to manually initiate the ADS is

required to prevent core uncovery. For the steam line break outside containment, a high drywell pressure concomitant with low reactor vessel water level and starting of a low pressure system pump does not occur; thus manual initiation of the ADS by the operator may be required. To eliminate the need for manual operator action, a combination of initiating signal logic that may eliminate this reliance is proposed for consideration. These ADS initiating signals are no HPCI or HPCS system flow plus low reactor vessel water level in conjunction with the starting of a low pressure ECC system pump and the 120-second timer. This combination of signals protects against a steam line break outside containment and a loss of feedwater with a stuck-open safety/relief valve, and provides protection against a single spurious signal initiating the ADS. In addition, if the RCIC and control rod drive systems have adequate capacity to prevent initiation of a low water level signal, even though they are not safety grade, the ADS will not actuate. Therefore, all BWR plants that have safety-grade high pressure coolant injection systems should consider modifying their ADSs to include this logic to eliminate the need for operator action.

Other than those areas identified above, no other features of the ADS system were found unacceptable or in need of improvement.

For BWR/1 and BWR/2 plants that do have safety-grade high pressure coolant injection systems, an alternate solution for automatic actuation of the ADS should be developed, or it should be shown by analyses that the acceptance criteria of 10 CFR 50.46 are not exceeded, or operator action for these plants is not needed for at least 20 minutes.

2.10 Reactor Venting

Gases generated during normal operation are continuously routed through the main steam lines into the turbine and main condenser with the normal steam flow. The steam jet air ejectors, which take a suction on the main condenser, remove the noncondensible gases and discharge them to the offgas system where the hydrogen is subsequently recombined in the catalytic beds, iodine is removed by charcoal filters, and the radioactive gases (xenon and krypton) are retained to decay until they can be vented to the atmosphere without exceeding acceptable limits.

If a transient or accident occurs which results in reactor isolation, the relief valves located on the main steam lines vent the steam and gases directly to the suppression pool. The relief valves open automatically on overpressurization. However, the ADS valves can also be opened remotely from the control room for venting. In addition, the reactor vessel has a head vent line with valves that can be remotely operated from the control room for venting.

Following a LOCA or actuation of the safety valves (for those plants with safety valves that vent directly to containment), a direct release path for gases to the primary containment exists. However, most BWR plant containments are normally inerted with nitrogen to maintain low oxygen content (less than five percent oxygen). The containment atmospheric dilution system, which utilizes nitrogen stored in tanks, is available for controlling hydrogen and oxygen concentration to prevent buildup of detonatable gases in the primary containment. In addition, several other methods such as containment atmospheric monitoring, hydrogen recombiners, and containment purge via the standby gas treatment system may be available to provide long-term hydrogen control. The Vermont Yankee and Hatch 2 plants currently do not have inerted containments, however, one of the short-term Lessons Learned recommendations (Item 2.1.5b of NUREG-0578) requires inerting for all Mark I and Mark II BWR plant containments of operating plants and plants with pending operating license applications. Two older plants, the Big Rock Point and Dresden 1 plants, do not have inerted containments. However, the licensees of these plants have provided information that indicate that the combination of core and containment size of these plants is such that explosive mixtures of hydrogen gas in the containment should not occur following a LOCA and, therefore, provisions for dealing with hydrogen gas are not necessary. This information has not been reviewed by the B&OTF.

2.11 Containment Spray/Cooling

The containment spray/suppression pool cooling subsystem is an intergral part of the RHR system. Following a LOCA, water pumped from the suppression pool through the RHR system heat exchangers can be diverted from core cooling to spray header loops located in the drywell and suppression chamber. The drywell spray condenses the containment atmosphere and collects in the bottom of the drywell until it reaches the level of the suppression pool vent lines. The water then overflows and drains back to the suppression pool. The suppression pool cooling line may be used for either suppression pool cooling or to spray in the suppression pool to condense steam and reduce suppression pool pressure.

The system may be operated by a keylock switch provided the core water level is at least two-thirds core height. A high drywell pressure is required to permit containment spray. The two-thirds core coverage interlock may be overriden by placing the keylock switch in the override position. The RHR system service water pumps are tripped following a LOCA; therefore, the keylock switch must be placed in the override position and the service water pumps started manually.

Following an accident in which low pressure coolant injection is required, low pressure coolant injection into the core is given first priority followed by suppression pool cooling and containment spray. This design is acceptable to the B&OTF.

2.12 Containment Isolation System

One of the basic purposes of the primary containment system is to provide a minimum of one protective barrier between the reactor core and the environmental surroundings subsequent to an accident involving failure of the piping components of the reactor primary system. Since a rupture of a line penetrating the containment and connecting to the reactor coolant system may be postulated to take place at the containment boundary, the isolation valve for that line is required to be located within the containment. This inboard valve in each line is required to be closed automatically on various indications of loss of reactor coolant. Additional reliability is added if a second valve, located outboard of the containment and as close as practical to it, is included. This second valve also closes automatically if the inboard valve is normally open during reactor operation. By physically separating the two valves, there is less likelihood that a failure of one valve would cause a failure of the second valve. The two valves in series are provided with independent power sources.

The isolation valves are grouped into four basic classes:

Class A - Those valves on process lines that communicate directly with the reactor vessel and penetrate the primary containment. These lines generally require two valves in series - one inside the primary containment and one outside the primary containment. Both valves close automatically on an isolation signal.

Class B - Those valves on process lines that do not directly communicate with the reactor vessel, but penetrate the primary containment and communicate with the primary containment free space. These lines generally require two valves in series, both of them outside the primary containment. Both valves close automatically on an isolation signal.

Class C - Those valves on process lines that penetrate the primary containment but do not communicate directly with the reactor vessel or with the primary containment free space and are not on lines that communicate with the environs. These lines require one valve, outside the primary containment, that closes automatically by process action (e.g., reverse flow) or by remote manual operation.

Typically, there are three sets of lines that penetrate the containment boundary. These are:

(1) Lines that go from the containment atmosphere into the reactor building to the redundant standby gas treatment system.

(2) Lines that go from the sumps in the containment to the radwaste building.

(3) Lines (which are normally open during operation) that go from penetrations on the reactor pressure vessel through the containment to systems in the reactor building or auxiliary equipment building.

All three containment penetration schemes have diverse signals for isolation. The diversity is provided by containment pressure backed up by reactor vessel water level for the lines that penetrate into the containment atmosphere and containment sumps. Normally-open lines that travel through the containment from the pressure vessel to systems outside the containment through the isolation valves have diverse isolation signals from low water level which is diverse from the leak detection system downstream from the outboard isolation valve. A summary of the diversity of the isolation signals is provided in Table A-3.

TABLE A-3

DIVERSITY OF ISOLATION SIGNALS

Type of Line	Isolation Signals
Containment atmosphere to reactor building	(a) Reactor vessel water level (b) High containment pressure (c) High radiation in ventilation duct
Containment sumps to radwaste building	(a) Reactor vessel water level (b) High containment pressure
3. Reactor vessel to systems in reactor building, turbine building, or auxiliary building	(a) Reactor vessel water level (b) Leak detection system to which pipeline is connected

Provisions for detecting leakage outside the primary containment are discussed in NEDO-24708 for the following systems: Residual heat removal, high pressure coolant injection, reactor core isolation cooling, shutdown containment (reactor) cooling, high pressure core spray, low pressure core spray, reactor water cleanup, isolation condenser, and feedwater and feedwater coolant injection.

In general, the leak detection instrumentation relies on local air space temperature sensors and/or flow monitoring pressure switches for high temperature fluid leakage. Leakage of low temperature fluid in the equipment areas and pipe routing areas is detected by monitoring the flow in equipment area drains and the reactor building floor drain sumps. In some systems, process flow rate is monitored. Other methods such as tank levels, radiation monitoring, dewpoint monitoring, pressure monitoring, and differential pressure switches also provide means of leak detection.

Those lines which could potentially transfer radioactive liquids and gases out of containment and of the diversity of the containment isolation signals for these lines are also addressed in NEDO-24708. Design requirements and leak detection are also addressed to a limited extent in NEDO-24708. A substantial part of the containment isolation discussion was not submitted until November 1979 and, therefore, was not reviewed in detail.

A perusal of information in safety analysis reports on MSIV leak detection indicates that the MSIV leak detection systems will only operate at low pressure. If fuel damage occurs as a result of a small-break LOCA and the reactor is at high pressure, it may be necessary to depressurize the reactor to minimize leakage through the MSIVs and to allow the leak detection system to function. This should be addressed in the inadequate core cooling guidelines and procedures.

2.13 Service Water System

The service water system is designed to provide cooling water to both essential and non-essential plant systems and components during normal, abnormal, and accident conditions.

The design of the service water system varies from plant to plant. A typical service water system consists of two independent essential cooling trains. Each train is capable of providing the required cooling for a safe reactor shutdown following a design basis LOCA. Each train is powered from a separate essential alternating current power source.

The service water system provides cooling water from the ultimate heat sink (e.g., ponds, rivers. lakes, oceans) to the reactor building closed loop cooling water system heat exchangers, the turbine building closed-loop cooling water system heat exchangers, the residual heat removal system heat exchangers, various chilled water systems and room coolers, and the diesel-engine coolers.

Based on our review of NEDO-24708, we have identified the following areas where improvements are needed or consideration to improvements have been given:

(1) Since the Big Rock Point plant's service water system has only one cooling train and is powered from normal alternating current power, the licensee should verify the acceptability of the consequences of a loss of service water supply to essential plant components in the event of a loss of offsite power.

(2) Long-term operation of certain ECC systems (e.g., RCIC and HPCI systems) may require space cooling to maintain the pump room temperature within allowable limits. The utilities should verify for each plant, the acceptability of the consequences of a complete loss of alternating current power. It is the staff's current position that plant systems should be designed to withstand a complete loss of alternating current power for at least a two hours.

2.14 Reactor Building Closed Cooling Water System

The RBCCWS system, Figure A-14, is a closed-loop cooling water system which transfers heat from the components which may contain radioactive fluids to the service water system .

The design of the RBCCW system varies from plant to plant. A typical RBCCW system is designed to provide cooling water to both essential and non-essential plant systems and components inside the reactor building during normal, abnormal, and accident conditions. The RBCCW system consists of two independent cooling trains. Each train is powered from a separate essential ac power source.

The safety-related components cooled by the RBCCW system include the spent fuel pool cooling system heat exchangers and the reactor recirculation pump coolers. Any possible radioactive leakage from the reactor equipment would be confined to the RBCCW system which is monitored continuously for radioactivity. A surge tank is used to accommodate the system's volume swell and shrinkage and to provide a means for adding makeup water and inhibitors.

Based on our review of NEDO-24708, we have identified the following area where consideration of improvements may be needed:

The utilities should perform analyses or experiments, on a plant specific basis, to determine the consequences of a loss of cooling water to the reactor recirculating pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating current power for at least two hours.

2.15 Instrument Air System

The instrument air system is designed to provide sufficient compressed air to both essential and non-essential air-operated valves or controllers in the plant systems.

Figure A-14

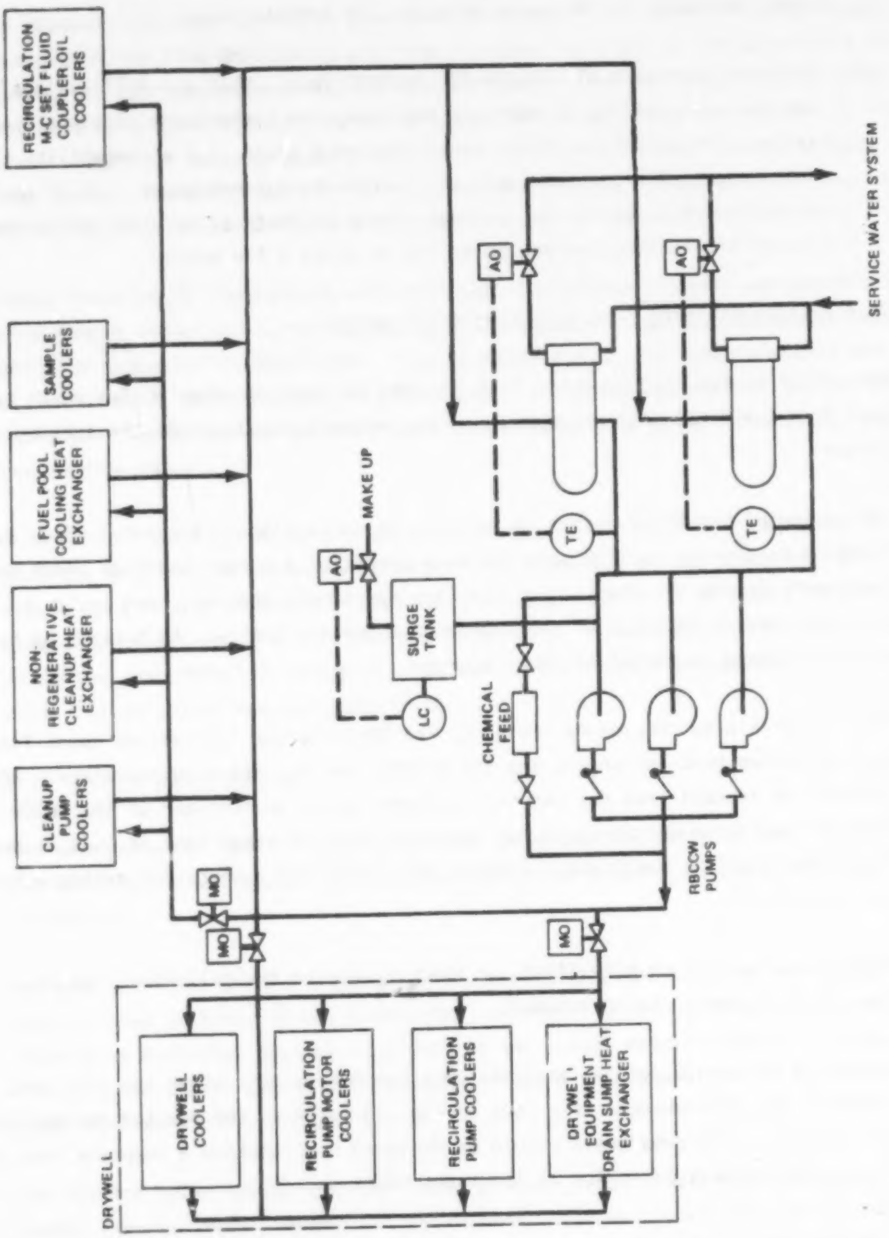

RECIRCULATION M-C SET FLUID COUPLER OIL COOLERS
SAMPLE COOLERS
FUEL POOL COOLING HEAT EXCHANGER
NON-REGENERATIVE CLEANUP HEAT EXCHANGER
CLEANUP PUMP COOLERS
MO
MO
MO
MAKE UP
AO
SURGE TANK
LC
CHEMICAL FEED
RBCCW PUMPS
TE
TE
AO
AO
SERVICE WATER SYSTEM
DRYWELL
DRYWELL COOLERS
RECIRCULATION PUMP MOTOR COOLERS
RECIRCULATION PUMP COOLERS
DRYWELL EQUIPMENT DRAIN SUMP HEAT EXCHANGER

Figure A-14 Reactor Building Closed Cooling Water System

The safety-related air operated valves are either provided with individual accumulators to properly position the valve, or are designed to fail in the safe position. Typically, the ADS, which requires a compressed gas to operate its valves, has a nitrogen accumulator backup system at the valves.

Based on our review of NEDO-24708, we have identified the following area where consideration of improvements may be required:

The licensees should verify that the safety/relief valves are provided with a sufficient quantity of air in the accumulators to cycle the valves open five times at design pressures after the design period of 100 days, even considering normal leakage. Otherwise, the utilities should show that the accumulator volume is acceptable and provide a basis.

2.16 Control Rod Drive System

The control rod drive system (Figure A-15) is supplied with pressurized water from the control rod drive hydraulic system to operate and cool the control rod drive mechanisms. Some of the water used for these functions is discharged into the reactor vessel and provides a backup source of cooling water in an emergency.

The system consists of two high-head, low-flow, 100-percent capacity pumps, piping, filter, control valves, hydraulic control unit, control rod drive mechanisms, and instrumentation. The condensate storage tank provides the source of water for the operation of this system. Pressure control valves control the pressure and flow of the control rod drive cooling water and the return water from the control rod drive system, both of which discharge into the reactor vessel. These control valves can be adjusted remotely from the the control room.

The portions of the control rod drive system that discharge water into the reactor vessel are non-safety grade and operate from normal alternating current power sources.

The control rod drive flow provides a source of cooling water to the reactor vessel during vessel isolation. This is particularly important for some BWR/1 and B/2 plants, for which this is the primary source of makeup on vessel isolation. The importance of this flow has been demonstrated during the 1975 Browns Ferry 1 fire and the 1979 Oyster Creek incident.

The control rod drive return line nozzle has experienced cracking in several operating BWR plants. GE's proposed system modification is total removal of the control rod drive return line and cutting and capping the control rod drive return line nozzle. BWR nozzle cracking is an NRC generic technical review activity (Task Action Plan A-10) that is currently under review.

We found no specific design features of this system that would adversely affect the functioning of the ECC systems or their components.

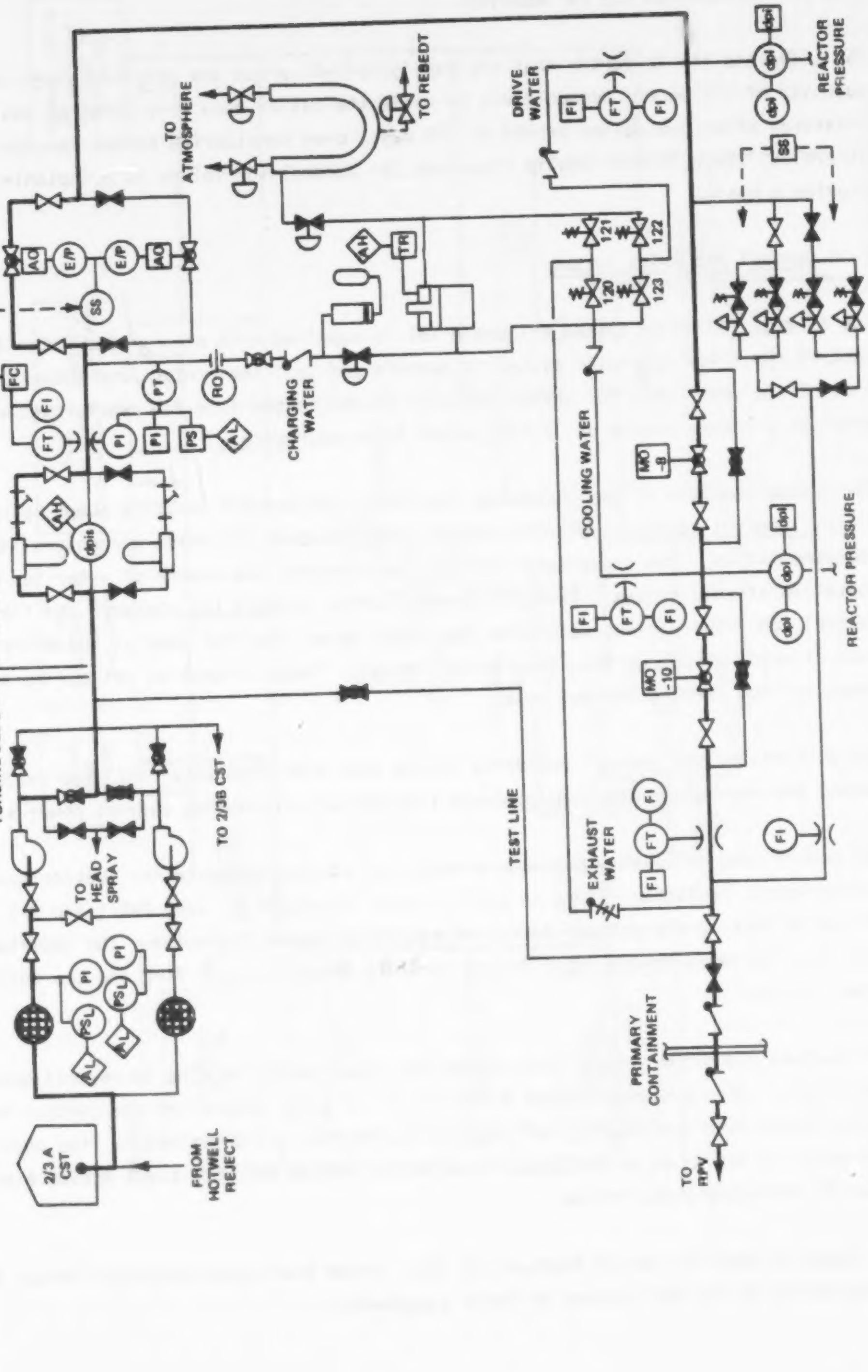

2/3 A CST
FROM HOTWELL REJECT
AL
PSL
PI
TO HEAD SPRAY
TURBINE BLDG
REACTOR BLDG
TO 2/3B CST
dpis
AH
FT
FI
FC
SS
E/P
AO
PT
PS
RO
CHARGING WATER
TO ATMOSPHERE
TO REBEDT
TR
DRIVE WATER
120
121
122
123
COOLING WATER
MO -8
MO -10
dpi
REACTOR PRESSURE
TEST LINE
EXHAUST WATER
PRIMARY CONTAINMENT
TO RPV

Figure A-15 Control Rod Drive Hydraulic System

2.17 Vessel Level Detection

Reactor vessel level is determined by differential pressure devices. Condensing chambers connected to the steam space in the reactor vessel are used as the reference leg. Pressure taps at different levels in the water space of the reactor vessel are used as variable leg sensing taps for narrow and wide range instruments.

Except as noted below for the reactor feedwater system level control, reactor water level measurement on BWR/1 through BWR/3 plants and some BWR/4 plants are equipped with Yarway temperature-compensating reference columns. The reference leg in each column is heated by condensate drainage from its condensing chamber.

The water level measurements for some BWR/4 plants and all BWR/5 plants use only non-heated reference columns which are maintained full of condensate by condensing chambers. In addition, reactor water level instrumentation used by the reactor feedwater system for reactor vessel level control and control room indication (or recording) on all BWR plants is equipped with ambient (non-heated) reference columns maintained by ambient-type condensing chambers.

Figure A-16 is a schematic of a typical Yarway temperature-compensated, constant- head chamber with heated reference leg located within the drywell. The reference leg and the variable leg are connected to a differential pressure (d/p) cell outside the drywell. The d/p cell serves as a local reactor water level indicator and has an integrally-mounted transmitter section for transmitting a signal proportional to the differential pressure to a remote indicator in the control room. The d/p cell also has a control module which is integral with the local d/p cell indicator. The control module provides the means to electrically initiate external functions such as alarms or emergency core cooling. Each control module typically has four switches for this purpose. Each four-switch control module is furnished with magnetically-activiated switches. Safety, control, and information functions provided by the Yarway instruments typically include scram, containment isolation, ECC system initiation, RCIC system initiation, ADS initiation (contribution), recirculation pump shutoff, MSIV closure, and readout and alarm functions in the control room.

The reference leg and the variable leg of the Yarways are surrounded by a reflective metal shield to provide a stagnant air space around the legs. Reactor steam continuously enters the condensing chamber, condenses, and drains back to the reactor through the variable leg. This maintains the temperature of the variable leg near the reactor operating temperature. The variable leg heats the reference leg, thereby providing partial temperature compensation in the reactor water level measurement.

The Yarways typically are calibrated to give correct indicated reactor vessel water level when the drywell ambient temperature is 135 degrees Fahrenheit and reactor operating temperature is 546 degrees Fahrenheit. For increases in drywell ambient temperature up to the temperature at which high drywell pressure will cause scram and other engineered safety feature initiations (maximum of about 100 Fahrenheit degrees

Figure A-16

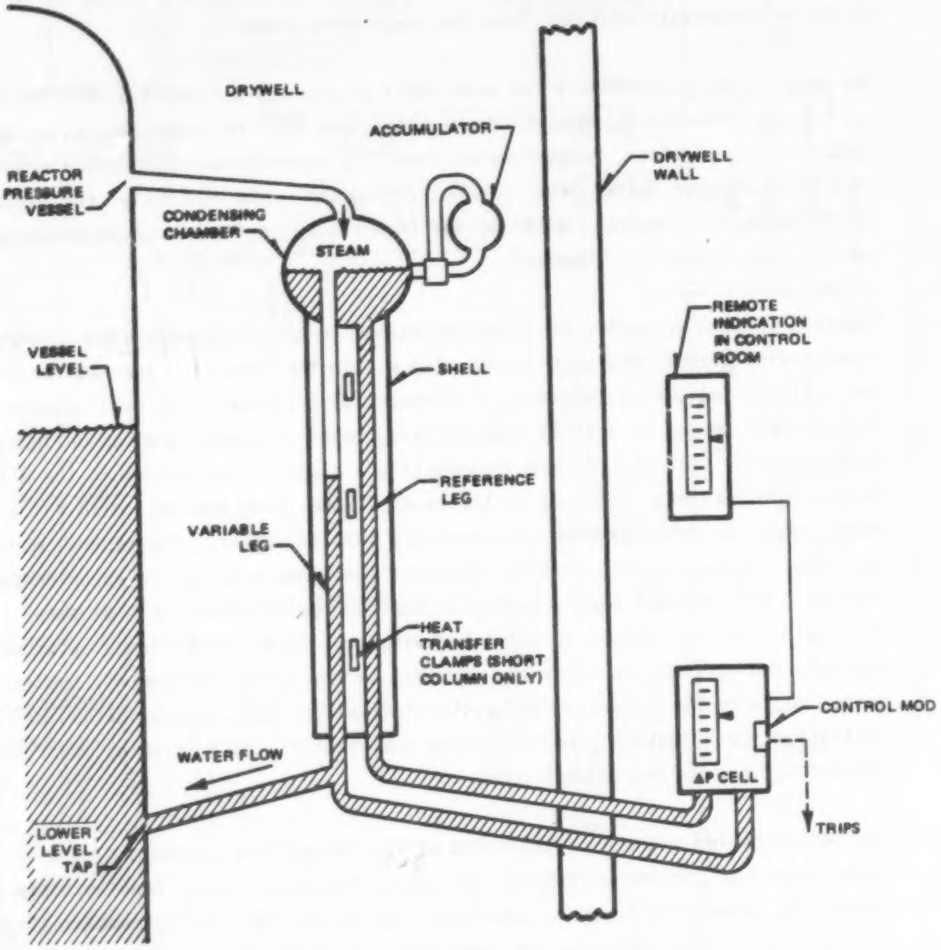

DRYWELL
ACCUMULATOR
DRYWELL WALL
REACTOR PRESSURE VESSEL
CONDENSING CHAMBER
STEAM
REMOTE INDICATION IN CONTROL ROOM
VESSEL LEVEL
SHELL
REFERENCE LEG
VARIABLE LEG
HEAT TRANSFER CLAMPS (SHORT COLUMN ONLY)
CONTROL MOD
WATER FLOW
ΔP CELL
TRIPS
LOWER LEVEL TAP

Figure A-16 Yarway Level Measuring Instrument Schematic increase from the normal 135 degrees Fahrenheit), the reference leg density change causes an indicated level change of about 2.2 percent which for a 200-inch column, will give an inaccurracy of less than five inches upscale (i.e., indicator will read higher than actual). A typical Yarway piping arrangement is shown in Figure A-17.

For the non-heated reference column level instruments, water level is sensed by the differential pressure produced between two columns of water - a cold (ambient temperature) reference leg, and a variable leg of reactor water. The cold reference leg is filled and maintained full by a condensing chamber at its top end which continuously condenses reactor steam and drains excess condensate back into the reactor vessel in the upper level tap connection to the condensing chamber. Figure A-18 illustrates the cold reference column instrument piping installation. Piping is sloped to avoid traps for non-condensibles and to provide high point venting of the water-filled instrument lines. Differential pressure sensors include d/p cells with electric transmitters and d/p switches located on instrument racks outside the drywell.

Safety control and information functions provided by the cold reference column level instruments include scram, containment isolation, ECC system initiation, RCIC system initiation, ADS initiation (contribution), feedwater control, recirculation pump shutoff, MSIV closure, and readout and alarm functions in the control room.

Figures A-19a through A-19d show the schematic composite reactor water level range coverage available to the control room operator for the various types of BWR plants.

The Humboldt Bay plant (BWR/1) has reactor water level indication in the control room which covers an overall range from approximately seven feet above the top of the active fuel to the top of the reactor vessel. This water level range is covered by a combination of wide range (10- and 18-foot Bailey columns) and narrow range (5-1/2 foot Yarway columns) instruments and there are four water level indicators in the control room including the two in the feedwater control system.

The Humboldt Bay plant has two indicators (one narrow and one wide range) and one recorder for water level indication associated with the feedwater control system. There are two narrow range (Yarway) indicators associated with the reactor safety system and ADS.

The Yarways provide automatic safety system trips, reactor isolation, and ADS initiation with a coincident high drywell pressure signal. The Yarways are arranged in redundant arrays such that one level instrument from each stilling well is in each of the two independent safety systems. A low level condition in either column will initiate the required safety functions.

The Humboldt Bay plant reactor vessel level instrumentation lines are attached to two stilling wells. Both stilling well lower taps are in the vessel downcomer region outside the ten-foot core shroud extension (chimney). One steam tap is just below the vessel flange and the other is in the vessel head. All of the water level instrument

Figure A-17

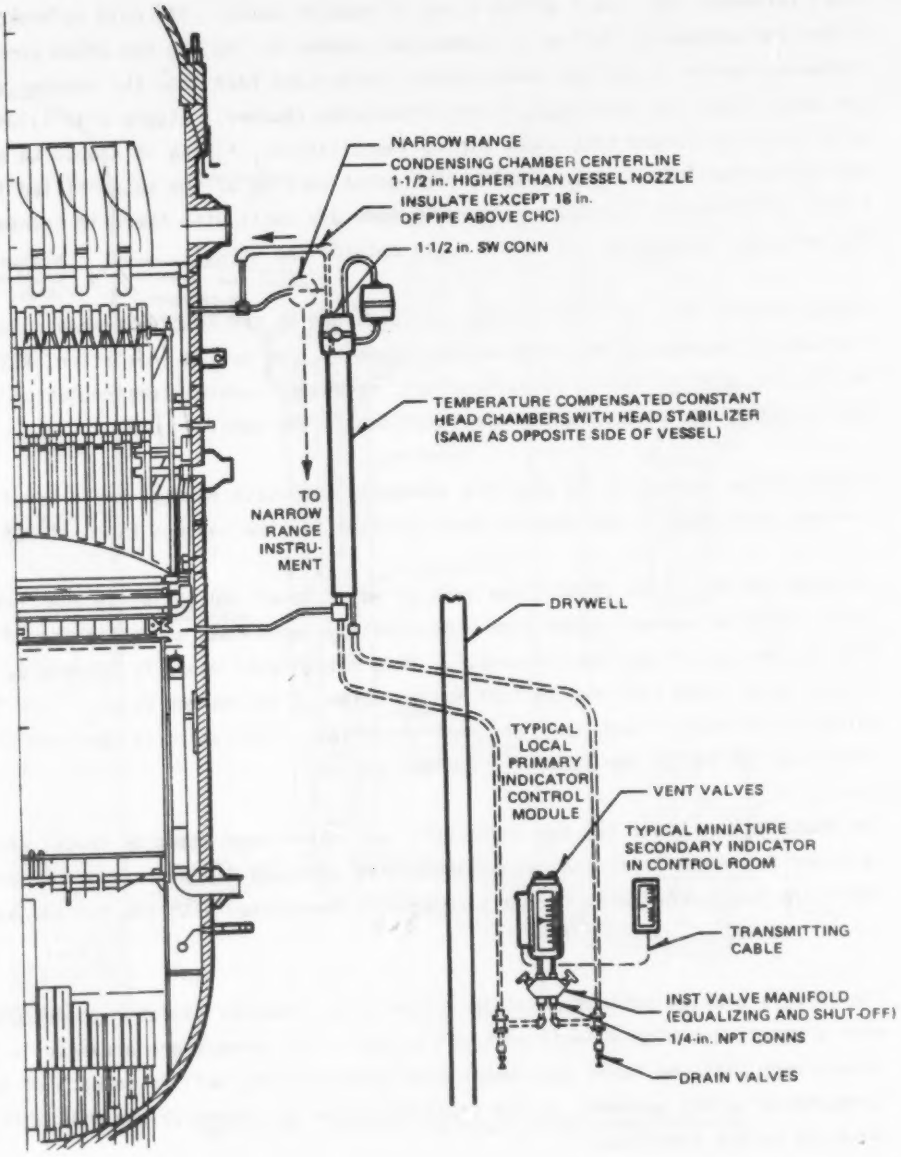

NARROW RANGE
CONDENSING CHAMBER CENTERLINE
1-1/2 in. HIGHER THAN VESSEL NOZZLE
INSULATE (EXCEPT 18 in.
OF PIPE ABOVE CHC)
1-1/2 in. SW CONN
TEMPERATURE COMPENSATED CONSTANT
HEAD CHAMBERS WITH HEAD STABILIZER
(SAME AS OPPOSITE SIDE OF VESSEL)
TO
NARROW
RANGE
INSTRU-
MENT
DRYWELL
TYPICAL
LOCAL
PRIMARY
INDICATOR
CONTROL
MODULE
VENT VALVES
TYPICAL MINIATURE
SECONDARY INDICATOR
IN CONTROL ROOM
TRANSMITTING
CABLE
INST VALVE MANIFOLD
(EQUALIZING AND SHUT-OFF)
1/4-in. NPT CONNS
DRAIN VALVES

Figure A-17 Typical 210 Inch Yarway Piping Arrangement

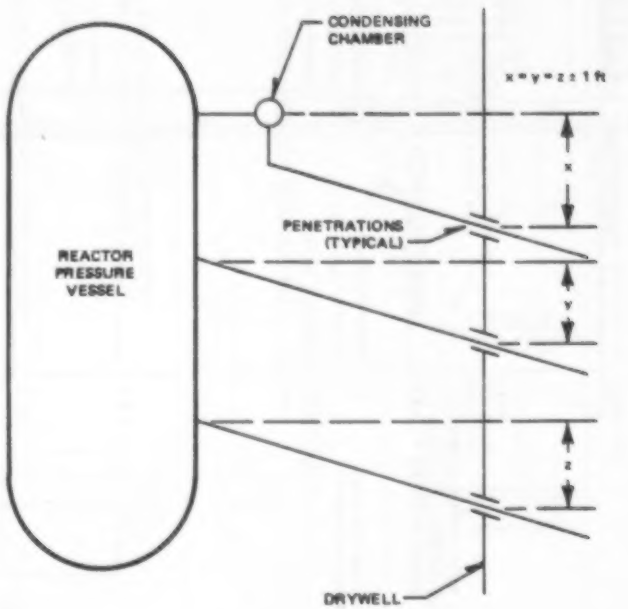

CONDENSING CHAMBER
x = y = z ± 1 ft
x
PENETRATIONS (TYPICAL)
REACTOR PRESSURE VESSEL
y
z
DRYWELL

Figure A-18 Requirements For Reactor Water Level Instrument Lines

Figure A-19a

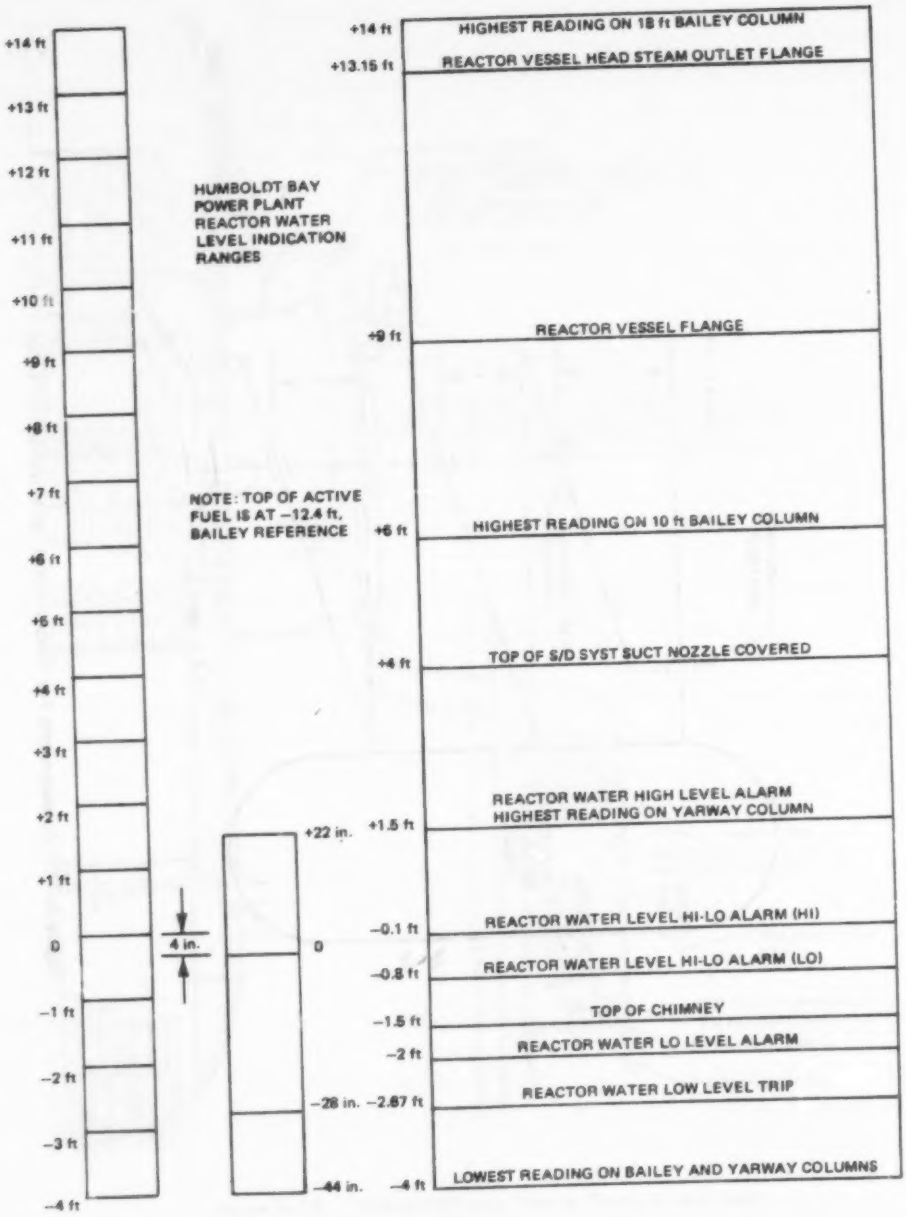

+14 ft
+13 ft
+12 ft
+11 ft
+10 ft
+9 ft
+8 ft
+7 ft
+6 ft
+5 ft
+4 ft
+3 ft
+2 ft
+1 ft
0
−1 ft
−2 ft
−3 ft
−4 ft
HUMBOLDT BAY POWER PLANT REACTOR WATER LEVEL INDICATION RANGES
NOTE: TOP OF ACTIVE FUEL IS AT −12.4 ft, BAILEY REFERENCE
4 in.
+22 in.
0
−28 in.
−44 in.
+14 ft
HIGHEST READING ON 18 ft BAILEY COLUMN
+13.15 ft
REACTOR VESSEL HEAD STEAM OUTLET FLANGE
+9 ft
REACTOR VESSEL FLANGE
+6 ft
HIGHEST READING ON 10 ft BAILEY COLUMN
+4 ft
TOP OF S/D SYST SUCT NOZZLE COVERED
+1.5 ft
REACTOR WATER HIGH LEVEL ALARM
HIGHEST READING ON YARWAY COLUMN
−0.1 ft
REACTOR WATER LEVEL HI-LO ALARM (HI)
−0.8 ft
REACTOR WATER LEVEL HI-LO ALARM (LO)
−1.5 ft
TOP OF CHIMNEY
−2 ft
REACTOR WATER LO LEVEL ALARM
−2.67 ft
REACTOR WATER LOW LEVEL TRIP
−4 ft
LOWEST READING ON BAILEY AND YARWAY COLUMNS

Figure A-19a Reactor Water Level Indication Ranges (Humboldt Bay)

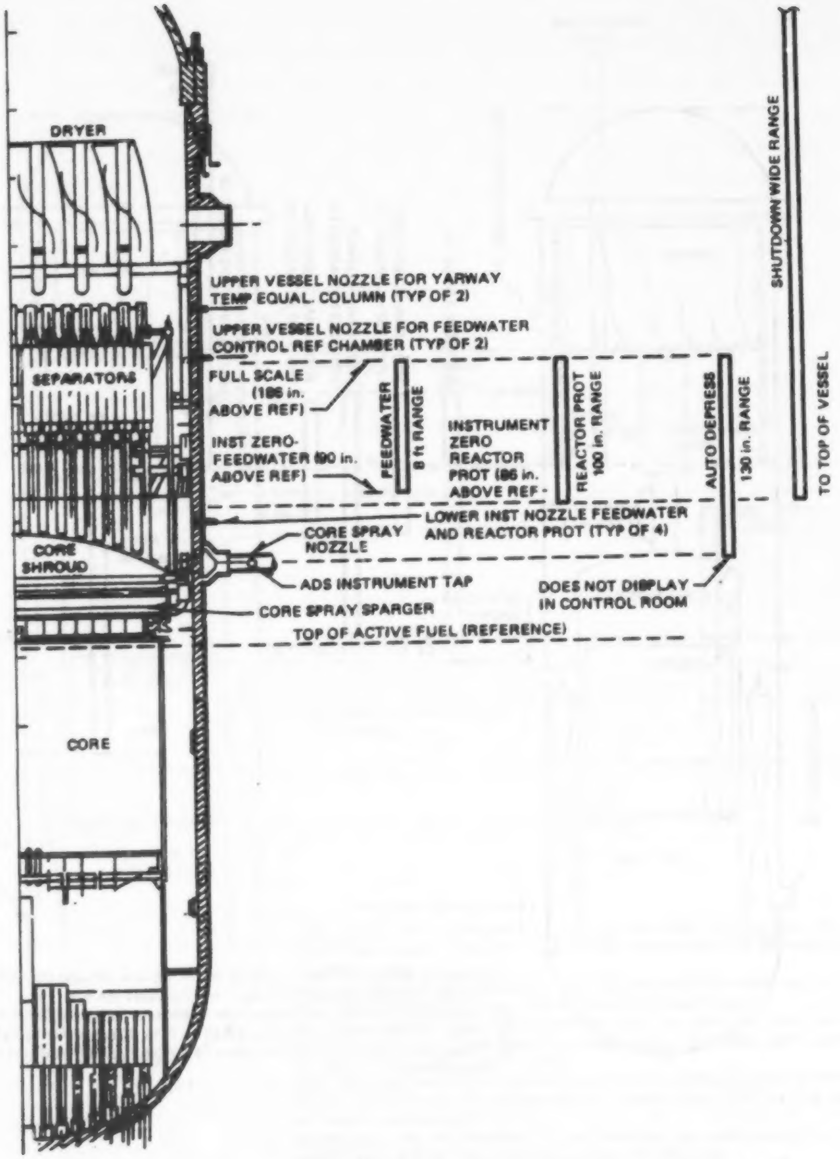
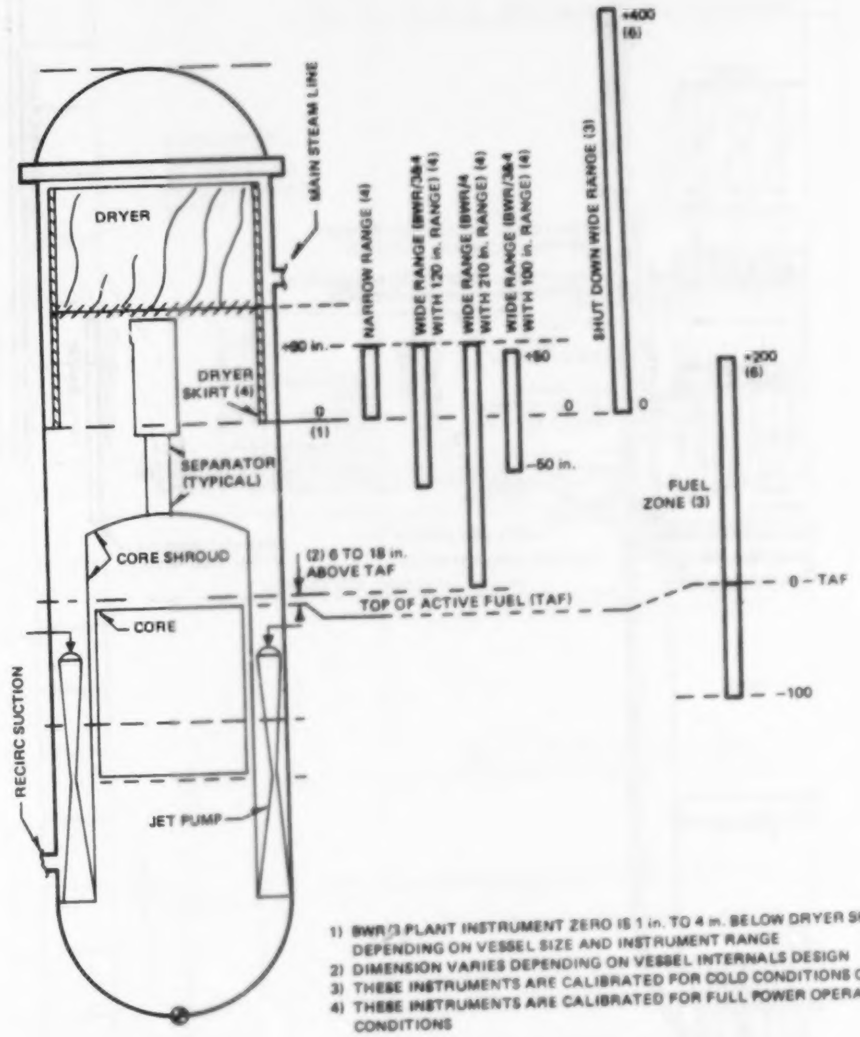

DRYER
SEPARATORS
CORE SHROUD
CORE
UPPER VESSEL NOZZLE FOR YARWAY TEMP EQUAL. COLUMN (TYP OF 2)
UPPER VESSEL NOZZLE FOR FEEDWATER CONTROL REF CHAMBER (TYP OF 2)
FULL SCALE (186 in. ABOVE REF)
INST ZERO-FEEDWATER (90 in. ABOVE REF)
FEEDWATER
8 ft RANGE
INSTRUMENT ZERO REACTOR PROT (86 in. ABOVE REF -
REACTOR PROT
100 in. RANGE
AUTO DEPRESS
130 in. RANGE
SHUTDOWN WIDE RANGE
TO TOP OF VESSEL
LOWER INST NOZZLE FEEDWATER AND REACTOR PROT (TYP OF 4)
CORE SPRAY NOZZLE
ADS INSTRUMENT TAP
DOES NOT DISPLAY IN CONTROL ROOM
CORE SPRAY SPARGER
TOP OF ACTIVE FUEL (REFERENCE)

Figure A-19b Typical Vessel Instrument Tap Location and Reactor Vessel Level Coverage (BWR/2 Plants)

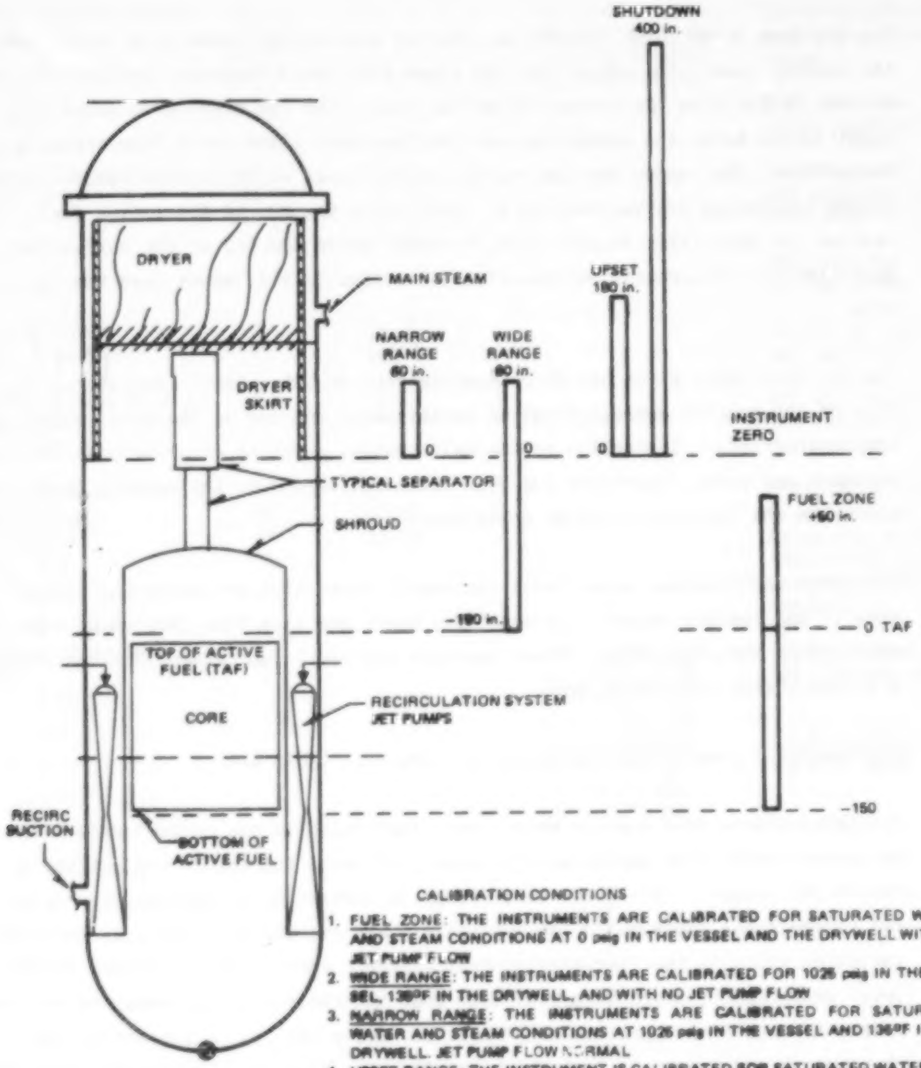
Figure A-19c


DRYER
MAIN STEAM LINE
+60 in.
DRYER SKIRT (4)
0
(1)
SEPARATOR (TYPICAL)
CORE SHROUD
CORE
RECIRC SUCTION
JET PUMP
(2) 6 TO 18 in. ABOVE TAF
TOP OF ACTIVE FUEL (TAF)
NARROW RANGE (4)
WIDE RANGE (BWR/3&4 WITH 120 in. RANGE) (4)
WIDE RANGE (BWR/4 WITH 210 in. RANGE) (4)
WIDE RANGE (BWR/3&4 WITH 100 in. RANGE) (4)
+60
-50 in.
0
SHUT DOWN WIDE RANGE (3)
+400
(6)
0
+200
(6)
FUEL ZONE (3)
0 - TAF
-100

1) BWR/3 PLANT INSTRUMENT ZERO IS 1 in. TO 4 in. BELOW DRYER SKIRT, DEPENDING ON VESSEL SIZE AND INSTRUMENT RANGE
2) DIMENSION VARIES DEPENDING ON VESSEL INTERNALS DESIGN
3) THESE INSTRUMENTS ARE CALIBRATED FOR COLD CONDITIONS ONLY
4) THESE INSTRUMENTS ARE CALIBRATED FOR FULL POWER OPERATING CONDITIONS

Figure A-19c Typical Reactor Vessel Level Range Coverage (BWR/3 and BWR/4 Plants)

Figure A-19d


SHUTDOWN
400 in.
DRYER
MAIN STEAM
UPSET
180 in.
NARROW
RANGE
60 in.
WIDE
RANGE
60 in.
DRYER
SKIRT
INSTRUMENT
ZERO
0
0
0
TYPICAL SEPARATOR
FUEL ZONE
+50 in.
SHROUD
–180 in.
0 TAF
TOP OF ACTIVE
FUEL (TAF)
CORE
RECIRCULATION SYSTEM
JET PUMPS
RECIRC
SUCTION
BOTTOM OF
ACTIVE FUEL
–150

CALIBRATION CONDITIONS

1. FUEL ZONE: THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER AND STEAM CONDITIONS AT 0 psig IN THE VESSEL AND THE DRYWELL WITH NO JET PUMP FLOW
2. WIDE RANGE: THE INSTRUMENTS ARE CALIBRATED FOR 1025 psig IN THE VESSEL, 135°F IN THE DRYWELL, AND WITH NO JET PUMP FLOW
3. NARROW RANGE: THE INSTRUMENTS ARE CALIBRATED FOR SATURATED WATER AND STEAM CONDITIONS AT 1025 psig IN THE VESSEL AND 135°F IN THE DRYWELL. JET PUMP FLOW NORMAL
4. UPSET RANGE: THE INSTRUMENT IS CALIBRATED FOR SATURATED WATER AND STEAM CONDITIONS AT 1025 psig IN THE VESSEL AND 135°F IN THE DRYWELL. JET PUMP FLOW NORMAL
5. SHUTDOWN: THE INSTRUMENT IS CALIBRATED FOR 120°F WATER AT 0 psig IN VESSEL AND 80°F IN THE DRYWELL. NO JET PUMP FLOW

Figure A-19d Typical Reactor Vessel Level Range Coverage (BWR/5 Plants) lower taps are located approximately seven feet above the top of the active fuel on the stilling well. The steam taps and condensed water source for the reference legs tap off at various positions along the stilling well depending upon the instrument's range. Since Humboldt Bay is a natural circulation BWR plant, these level instruments reflect the level of the water in the downcomer region during power operation and can be effective in determining the water level in the core and chimney when significant steam production is not occurring due to the direct connection between the core and downcomer.

The Big Rock Point plant (BWR/1) has reactor and reactor steam drum level indication in the control room. The ranges for the steam drum level feedwater control are ±25 inches and ±40 inches from the centerline of the drum. The low steam drum level trip is at eight inches below the centerline and the low level alarm is at four inches below the centerline. The ranges for the reactor vessel level which provide reactor protection system indication are two feet to 3.5 feet above the top of the active fuel. The reactor low level trip is at 2 feet, 9 inches above the top of the active fuel. Instrumentation for the reactor depressurization system is ±12 inches from the low level trip.

The Big Rock Point plant has five separate reactor water level indicators, including four on the reactor depressurization system panel and one on the main control panel in the control room. Indication on the main control panel is accurate when the reactor is shutdown and cold. There are two drum level indicators on the control panel. They are slaves to the indicators inside containment.

There are four reactor water level instrument taps which are above the thermal shield area in the reactor vessel. In addition, there are also four instrument taps, two on each end of the steam drum. Other pressure and level indications for the reactor and drum are shared with these taps.

The Dresden 1 plant level indicators are shown on Table A-4.

The BWR/2 plants have reactor water level indication in the control room which covers an overall range from approximately seven feet above the top of the active fuel to the top of the vessel. This water level range is covered by a combination of wide range and narrow range instruments and typically there are six indicators or recorders including those in the feedwater control system. Additionally, another reactor water level measurement, which is useful only when the recirculation pumps are not running, covers a range from approximately 4-1/2 feet above the top of the active fuel inside the core shroud, up to 11 feet above the top of active fuel inside the steam separator standpipes. This level is not indicated in the control room but triggers a low level alarm and an ADS trip permissive in the control room at a water level of approximately four feet above the top of the active fuel.

For the BWR/2 plants, there are six separate reactor vessel water level indications and recordings in the control room including two wide range reactor water level indicators associated with the safety system reactor water level measurement, two narrow range

TABLE A-4

DRESDEN 1 PLANT REACTOR WATER LEVEL INDICATION

Function	Existing	Installed For RPS	Installed for ECCS	Comments
Reactor Vessel Water Level	LSL-1 LSL-2 LSL-3 LSL-4		LSL 1-6141-125A LSL 1-6141-125B LSL 1-6141-125C LSL 1-6141-125D	Existing provides reactor safety system scram ECCS provides injection valve permissive.
Primary Steam Drum Water Level	LIS-12 LIS-13 LIS-14 LIS-15	LS-12 LS-13 LS-14 LS-15		Existing will remain and provide recirculation pump trip RPS provides safety system scram
Primary Steam Drum Level Recorder	* *	LR-2 LR-12		*Existing replaced with new equipment.
Primary Steam Drum Water Level Indicator	*	LI-6		RPS will provide level indication and recording
Primary Steam Drum Water Level Transmitter	** ** **	LT-1 LT-2 LT-12		**Existing indicating level transmitters being replaced with non-indicating type. Also provides feedwater control.
Primary Steam Drum Level			LI 1-6141-110A LI 1-6141-110B LI 1-6141-110C LI 1-6141-110D	Level indication - HPCI system building
			LI L-6140-55A LI 1-6140-55B LI 1-6140-55C LI 1-6140-55D	Level indication - Control Room

indicators, one level recorder associated with the reactor feedwater and vessel level control system, and one shutdown wide range level indicator which uses a separate reference chamber located so that water level indication is available all the way to the top of the vessel.

Those monitors, which provide automatic safety initiation trips, are arranged in redundant arrays such that at least two instruments for each water level range are in each of two independent divisions. A level trip in either division will initiate the required safety function.

There are four steam space taps which sense the steam annulus outside the dryer support skirt. Two are used for the feedwater level control reference leg and two are used for the safety system level measurement and trip instrumentation reference legs. There are four lower taps (water zone) which sense the water variable leg inside the vessel annulus outside the core shroud at approximately six feet above the top of the active fuel. There are two taps (one in each core spray header) which sense the water variable leg inside core shroud above a level of approximately 4-1/2 feet above the top of the active fuel. These taps are effective for water level inside the shroud only when the reactor recirculation pumps are stopped and core spray pumps are not delivering water to the core spray spargers.

The BWR/3 through BWR/5 plants have reactor water level indication in the control room which covers a range from approximately the bottom of active fuel to the top of the vessel. Typically, there are 10 or 11 reactor water level indicators or recorders, including those in the feedwater control system, on the main control room front panels. These readouts for the various ranges and functions are in addition to the indicators on the trip units for plants having trip units in the main control room.

There are typically nine or ten separate reactor vessel water level indications provided in the control room for the BWR/3 and BWR/4 plants. The indications and recordings in the control room include two wide range indications associated with the safety system reactor water level measurements, two or three narrow range indicators and one narrow range recorder associated with the feedwater control system level measurement, two indicators and one recorder associated with the level measurement inside the core shroud (fuel zone), and one shutdown wide range indication, which uses a separate reference column of water located so that water level indication is available all the way to the top of the vessel.

Those monitors which provide automatic safety equipment initiation are arranged in a redundant array such that at least two or more instruments for each water level range are in each of two or more independent divisions. A level trip in any division will initiate the required safety function.

Typically there are eleven reactor vessel water level indications provided in the control room for the BWR/5 plants. The eleven indications in the control room include two wide range level recorders and one wide range level indicator, three narrow range level indicators and one narrow range recorder, one fuel zone level indicator (and one fuel zone level recorder), one upset range level recorder and one shutdown wide range level indicator. On those plants which are provided with level transmitters and indicating analog trip units in lieu of level switches, 23 additional level indications are provided in the control room (but not on the front panels).

Those monitors used to provide automatic safety equipment initiation are arranged in a redundant array such that at least two or more instruments for each level range are in each of two or more independent divisions. A level trip in either division will initiate the required safety action.

For the BWR/3 plants, there are two steam space taps which sense the steam annulus outside the steam dryer. These taps are shared by the feedwater level control system instrumentation and the reactor safeguards water level instrumentation and are used for the reference legs in both sets of instrumentation.

There are two lower taps (water zone) which sense the water annulus outside the core shroud at approximately six feet above the top of the active fuel. These taps are shared by the feedwater level control system instrumentation and the safeguards water level instrumentation and are used as the variable legs for both sets of instrumentation.

There are two taps (one on each of two jet pump diffusers) which sense the level as follows: with reactor recirculation pumps stopped, the level variable leg (i.e., water leg) is sensed in the vessel water annulus outside the core shroud above the jet pump diffuser tap, which is located approximately five feet below the bottom of the active fuel. This measurement also reflects the mixture level (collapsed liquid level mass equivalent) inside the core shroud above the variable leg taps. When level is below the top of the jet pumps (approximately 2/3 core height), the taps sense level inside the jet pumps above the diffuser tap and inside the core shroud rather than the vessel annulus level.

For BWR/4 plants with Yarways and later BWR/4 plants without Yarways, there are two upper steam space taps, similar to these BWR/3 plants. There are two intermediate (water zone) taps which sense the water variable leg inside the vessel annulus approximately 13 feet above the top of the active fuel. There are two lower taps which sense the water variable leg inside the vessel annulus outside the core shroud at above approximately 1/2 foot above the top of the active fuel.

There are two lower taps which sense the water variable leg inside the jet pump above the jet pump diffuser tap, similar to those on BWR/3 plants.

For the later BWR/4 plants with cold reference chambers only, and for the BWR/5 plants, there are four upper steam space taps which sense the steam annulus outside the dryer skirt used for reference legs for reactor water level measurements. There are two intermediate water zone taps which sense the water variable leg inside the vessel annulus above approximately thirteen feet above the top of the active fuel. There are four lower water zone taps which sense the water level inside the vessel annulus above approximately 1/2 foot above the top of the active fuel. There are two lower taps which sense the water level inside the vessel annulus above the jet pump diffuser taps, similar to those of the BWR/3 plants.

All plants using jet pumps (BWR/3 through BWR/5 plants) have fuel zone range level indication and recording using a cold reference column system with a condensing chamber shared with the narrow range level instruments and a lower tap connected into the jet pump diffuser several feet below the bottom of the reactor core support plate (Figure A-20). This range overlaps the wide range under all operating conditions. The function of this measurement is primarily for information purposes, except on earlier plants where it serves as a bypassable permissive for containment spray initiation.

This instrument is calibrated to read the correct vessel water level when the vessel is depressurized and with the reactor recirculation pumps shut off. With the reactor in this condition, the instrument accuracy is comparable to the narrow range level cold reference column instruments. The inaccuracy introduced by natural convection and ECC system flow through the jet pumps is small (less than one-inch water column).

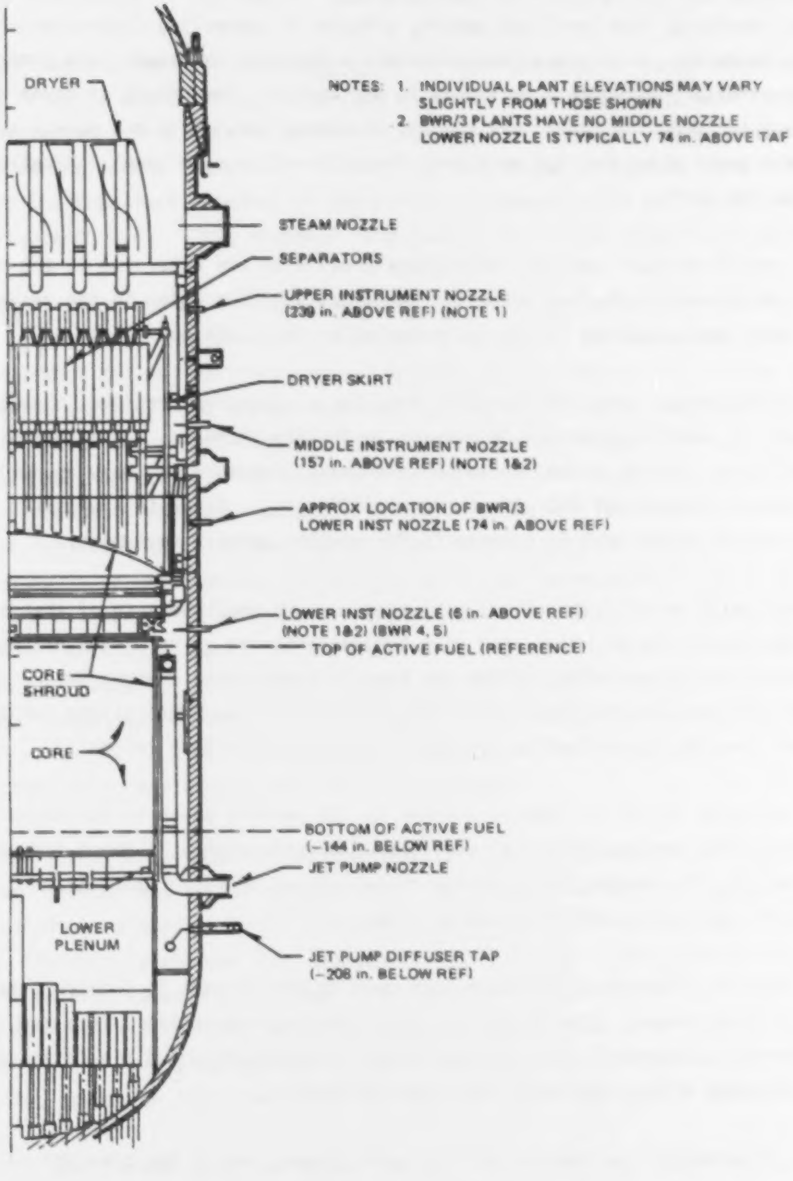
The differential pressure method of measuring vessel water level senses the weight of fluid above the lower instrument tap and is calibrated in terms of water at a predetermined density. Therefore, its reading is a collapsed liquid level measurement (the equivalent level of single-phase liquid). The reading is thus a representation of the mass of water above the sensing tap rather than an indication of the actual fluid surface, which will be higher than indicated if steam is present in the reactor water.

The specific volume of water depends on its temperature. Subcooling of 20 BTU/lb in the annulus below the narrow range middle instrument tap on BWR/4 and BWR/5 plants is accounted for. This subcooling is accounted for in the calibration to be effective in the reactor water below the middle instrument tap and to have no effect above the tap. The subcooled water introduces approximately a 1.8 percent density increase in the reactor water at the normal operating pressure of 1000 psig. This results in an indicated increase in level of approximately 1.8 percent of the of distance between the lower wide range tap and the narrow range (middle tap). For a typical plant, this would result in a higher level indication on the wide range instrument of about three inches of reactor water.

The subcooling also exists on BWR/1 through BWR/3 plants, but has not been factored into the calibration. The subcooling in the BWR/1 through BWR/3 plants introduces an insignificant error because the lower tap is not far below the feedwater sparger. The error is estimated to result in a maximum of one-inch increase in the indicated water level.

The effect of fluid density variation with pressure is small due to the near-incompressibility of water. The effect of carryunder of steam into the vessel annulus water has a small effect on sensed water level, estimated to be a two inch decrease in

Figure A-20


NOTES: 1. INDIVIDUAL PLANT ELEVATIONS MAY VARY SLIGHTLY FROM THOSE SHOWN
2. BWR/3 PLANTS HAVE NO MIDDLE NOZZLE LOWER NOZZLE IS TYPICALLY 74 in. ABOVE TAF

DRYER
STEAM NOZZLE
SEPARATORS
UPPER INSTRUMENT NOZZLE (239 in. ABOVE REF) (NOTE 1)
DRYER SKIRT
MIDDLE INSTRUMENT NOZZLE (157 in. ABOVE REF) (NOTE 1&2)
APPROX LOCATION OF BWR/3 LOWER INST NOZZLE (74 in. ABOVE REF)
LOWER INST NOZZLE (6 in. ABOVE REF) (NOTE 1&2) (BWR 4, 5)
TOP OF ACTIVE FUEL (REFERENCE)
CORE SHROUD
CORE
BOTTOM OF ACTIVE FUEL (−144 in. BELOW REF)
JET PUMP NOZZLE
LOWER PLENUM
JET PUMP DIFFUSER TAP (−208 in. BELOW REF)

Figure A-20 Typical Instrument Tap Locations BWR/3, BWR/4, and BWR/5 Plants indicated level (i.e., instrument reads two inches lower than the actual level) and has no effect below the dryer skirt level. The effect of carryover of water into the main steam is to increase the pressure drop across the dryer assembly slightly because of the mass flow increase and thus depress the water level inside slightly, resulting in an indicated level slightly higher than actual. The effect of carryunder is to reduce the density of the water outside and above the dryer skirt level, resulting in an indicated level slightly lower than actual. The overall effect on vessel level measurement resulting from the fluid density effects of subcooling (approximately a three-inch increase), carryunder (approximately a two-inch decrease), and compressibility (approximately a two-inch decrease) is negligible. The effect of dryer d/p (carryover effect included) is taken into account in vessel level trip set points above the bottom of the dryer skirt but has no effect for trip settings or level indication for levels below the skirt.

The vessel pressure and the temperature profile of the water leg in the reactor annulus are the strongest factors affecting the density of the water in the vessel annulus and as such, are accounted for in the calculation for scale end point.

As actual vessel pressure increases from the calibration pressure, the water density decreases, and for pressure decreases the density increases, in accordance with saturated conditions. During normal operation the vessel pressure may vary approximately 100 psig (typically from about 920 psig to about 1020 psig). Since this pressure variation is small there is no need to compensate for annulus density variations.

Vessel water density variations with pressure are small because of the near-incompressibility of water, but also because pressure is held constant by the main steam pressure regulating system and because power level changes are relatively slow, especially on typical base-loaded BWR plants. For the BWR/1 plants, which have their lower tap slightly below the feedwater sparger, the effect is small.

The pressure variation from zero power to 100 percent power is approximately 100 psi (worst case) and results in a vessel water density change of about 1.8 percent. This translates into a mid scale (narrow range) effect of less than 0.5 inch, which is not significant from a control point of view.

The actual differential pressure cell used in measurement is located some distance from the reactor vessel. The response time of the instrument lines from the vessel to the differential.pressure cell and the dynamic response of the differential pressure cell itself both affect the level response indication.

The instrument lines respond with acoustic speeds due to the pressure wave traversing along the instrument line. The time delay expected in the instrument response is 25 to 50 milliseconds. At the highest expected level response rates of eight to ten inches/second (due to pressurization transients), the instrument line error is about 0.5 inch water column and is accounted for in the transient simulation of sensor dynamics. Verification of this response time for typical plant instrument lines can be obtained from EPRI NP-564, "Transient and Stability Tests at Peach Bottom Atomic Power Station Unit 2 at end of Cycle 2," dated June 1978. By comparing the natural frequency of the reactor pressure measurement in Table B-7 of EPRI NP-564 with the fundamental mode response of a single closed end tube resonator (f=C/4L where C is sonic speed and L is tube length), it is possible to compute C=3860 feet/second which is in good agreement with measured or theoretical sonic speeds at these conditions. This allows verification of the time delay in the sensor lines which further corroborates the 0.5 inch error.

Further testing has been performed by GE to span the rate of level response for blowdown rates of up to about 125 psi/second which yields level rate response of eight to ten inches/second. This rate is typical of observed and expected level transient response rates during severe transients in BWRs. In this range of testing, the level indication showed the transient response of the pressure transducers to be within ± one inch of the expected level. This response is accounted for in the transient simulation analysis.

A drywell temperature different from that for which the cold reference leg level measurement system is calibrated, has a predictable effect on the indicated level as a result of reference column density changes. Drywell ambient temperature changes during normal operation are small and are not expected to increase by more than approximately 60 Fahrenheit degrees above normal. The effects of such changes are small and do not affect plant operation. The magnitude of the effect is determined by the temperature changes (density change from calibrated value), the vertical height of the reference column subjected to the temperature change, and the type of reference column used. For increases in drywell ambient temperature up to the temperature at which high drywell pressure will cause scram and other engineered safety feature initiations (maximum of about 60 Fahrenheit degrees to 100 Fahrenheit degrees increase from the normal 135 degrees Fahrenehit), the density changes are small. This reference column density change, causes an indicated level change of about 2.2 percent which, for a 200-inch water column, will give an inaccuracy of less than five inches upscale (i.e., the indicator will read higher than the actual level).

For the Yarway reference column, the reference column average temperature is intermediate between ambient and vessel temperature. The Yarway manufacturer suggests 300 degrees Fahrenheit as a nominal average temperature for the reference column. At this temperature, the density changes with temperature at a rate of 0.062 percent/Fahrenheit degree. For an ambient temperature change of 60 Fahrenheit degrees, the reference column temperature changes less than 30 Fahrenheit degrees, which gives a density of less than two percent. The resulting density, which is approximately 120 percent of vessel water density, causes an indicated level increase of approximately 2.4 percent.

After a small-break LOCA, the drywell may be at a relatively high temperature for some time, during which those reactor pressure vessel level indications which are affected by drywell temperature will be higher than actual. The ECC system trip points, correspondingly, will be effectively lower than intended.

The effect of this trip point shift has been shown by calculation to be inconsequential from a safety standpoint, but it could result in a reduction in redundancy of the initiating signals of the ECC systems and lead to some misinterpretation of actual reactor vessel water level by the operator.

The Yarway remote liquid level instruments for both the short column instruments used on BWR/1 plants (18-inch and 66-inch scale lengths) and on most BWR/2 and BWR/3 plants (100- to 120-inch scale length) have reference columns which are heated (see Figure A-16). Large changes in ambient temperature can result in changes in the temperature of this heated reference column and result in differences between measured and actual reactor vessel water level.

Other instruments used for BWR vessel water level measurements and trips have cold reference columns. The cold reference leg instruments include the lo-lo-lo level switches for ADS initiation in certain BWR/2 plants, all the narrow range level instruments for feedwater control,* the fuel zone level indicators, and for some BWR/4 plants the scram (Level 3) and high level trip switches (Level 8). The BWR/5 plants and some late BWR/4 plants are required to have their sensing lines routed out of the drywell as shown in Figure A-18. Instruments with such routing are not affected by varying drywell temperature since the vertical lengths of the sensing lines within the drywell are approximately equal.

Evaluations have been made of the effects of high drywell temperature on the BWR/4 plant scram and high level trip functions for plants not having installations in accordance with Figure A-18. There would be little or no impact on the scram or high level trip functions since scram initiation will occur quickly after the initiating event and there will be little time to cause any significant level discrepancy, and HPCI/RCIC system shutoff will not affect overall system performance.

Large increases in drywell temperature, such as could occur during a pipe rupture in the drywell, would cause the reference leg of the Yarway instrument to heat up. As the reference leg water temperature increases, the reference leg water density will decrease causing the sensed d/p to decrease, even if the variable leg level and temperature were to remain unchanged. This decreasing d/p would register as an increasing vessel level on the d/p cell indicator and the remote indicator.

The magnitude of the level indication change depends upon the temperature transient in the drywell, the thermal response time constant of the Yarway reference leg, and the length of the reference leg water column. If it is assumed that (1) the drywell is maintained at the maximum temperature which would result from a small steam line break, (2) the Yarway reference leg has reached its equilibrium temperature, and (3) the variable leg level is low, the indicated reactor vessel water level can be higher than the true level by 12.7 percent of the reference leg's total length (scale length + six inches top suppression and + six inches bottom suppression). This means a Yarway instrument with a 210-inch scale length could, given the foregoing assumptions, experience a maximum inaccuracy of + 12.7 percent of 222 inches, or + 28 inches in the indicated reactor vessel water level. Actual level indication changes due to increasing drywell temperature will occur rather slowly since the thermal time constant of the Yarway reference leg is calculated to be 20 to 30 minutes.

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*"Bailey feedwater control on Some BWR/1 plants use a saturated reference column and are thus an exception.

Given the conservative assumptions described above, true reactor vessel water level on (for example) a BWR/4 plant with 210-inch Yarway scale length could fall to below the lower level tap elevation with the instrument still indicating a water level of 23 inches above the lower tap elevation. Once true level falls below the lower tap, the instrument will not sense further level decrease. Since the Level 1 trip point for BWR/4 plants is 13 inches or less above the lower tap, there exists the potential that level trips will not occur at the prescribed setpoint. In addition the operator could believe the water level is stable at some level when in fact the true level could be lower. A similar situation could occur in the BWR/2 and BWR/3 plants. The effects of this potential level inaccuracy are discussed below.

With the exception of the RCIC system and the ADS, all ECC systems in the BWR/3 and BWR/4 plants start as a result of a low level or a high drywell pressure signal. The RCIC system starts as a result of low level only and ADS initiates on low level and high drywell pressure. Since all LOCAs inside the containment will result in high drywell pressure before low level is reached, the HPCI, LPCS, and LPCI system will all start during a LOCA regardless of temperature effects of level instrumentation.

The impact of high drywell temperature on the level instrument initiating the RCIC system and the ADS for the three general categories of steam line breaks, assuming HPCI system failure, is discussed below. (Steam line breaks lead to larger inaccuracies than liquid line breaks and, therefore, were selected for detailed study).

(1) Breaks Greater Than About 0.5 Square Feet

The reactor vessel depressurization rate is sufficiently fast that ECC system will start on high drywell pressure and vessel level will increase before the ADS level trip is received. Therefore, the ADS trip is not required to function.

(2) Breaks Smaller Than About 0.1 Square Feet

For BWR/3 plants and the Vermont Yankee plant, all expected ECC system level trips will be received before the reference column has an opportunity to heat up enough to preclude the trips. Therefore, drywell temperature changes will not impact ECC system redundancy. For all remaining BWR/4 plants, the RCIC system will start and maintain vessel level before the ADS level setpoint is reached. Therefore, the ADS trip is neither expected nor required to function.

(3) Breaks Greater Than About 0.1 Square Feed But Less Than About 0.5 Square Feet

For the BWR/3 plants and the Vermont Yankee plant, all expected level trips will be received before the reference column has an opportunity to heat up enough to preclude the trips. Therefore, drywell temperature changes will not impact redundancy. For the all remaining BWR/4 plants, the RCIC system will start and the combination of the RCIC system operation and the break will depressurize the vessel and thus cause initiation of low pressure. Therefore, the ADS trip is not required to function.

The Oyster Creek and Nine Mile Point plants (BWR/2s) do not use Yarways for the Level 1 ADS trip functions; however, the instrument used is affected by high drywell temperature. The LPCS system will start on a low level trip (Yarway) or a high drywell pressure trip. Thus if a low level trip were precluded, the drywell pressure signal would start the LPCS system.

For the BWR/1 plants, the lower tap is sufficiently below the trip point to preclude malfunction due to ambient temperature effects.

Licensees of BWR plants have recently been advised by GE to emphasize this possible ambient temperature effect to their operators, to take steps to make it unlikely to mislead the operators, and to adjust certain and related trips to compensate for that effect.

Recent measurements of the temperature of the Yarway reference leg temperature at the Quad Cities plant show that the average temperature for normal operating condition is higher than predicted by GE. The higher temperature resulted in a level measurement error of six inches. The instruments at the Quad Cities plant have been recalibrated to account for this error, but the same problem may exist on other plants. A plant-by-plant check of the temperature is needed.

A small-break LOCA has the potential for heating the drywell atmosphere to over 212 degrees Fahrenheit. Since the reference leg in temperature-equalized instruments normally operates at well above the drywell temperature, the possibility of the reference leg boiling as the reactor depressurizes during small-break LOCAs was analyzed by GE.

The analyses assumed that the drywell heatup instantaneously to 340 degrees Fahrenheit, the maximum value it can attain. Following this drywell heat-up the temperature distribution in the reference leg would be higher than during normal operating conditions. In order to bound the condition, it was arbitrarily assumed that all level instrumentation would read high (Level 8) as a result of boiling as the reactor pressure reached 425 psia (corresponding to the maximum saturation pressure of the liquid in the reference leg). These bounding analyses showed that for all break sizes, the reactor either depressurizes fast enough to allow timely initiation of the low pressure system on high drywell pressure, or the breaks are small enough that (at worst) ECC functions occurred before the potential boiling of the reference leg fluid.

In addition, the consequences of different rates of manual depressurization were also considered ten minutes after the event and following the instantaneous attainment of the peak drywell temperature. These analyses show that the low pressure ECC systems will inject independent of any boiling that may occur.

In instruments with cold reference legs, the reference leg temperature could increase to the drywell ambient temperature, which will not exceed 340 degrees Fahrenheit. Thus, under the least favorable possible conditions, a cold reference leg will not boil until the system pressure falls to 118 psia (saturation temperature at 340 degrees Fahrenheit). Thus, pressure maintained above about 100 psig is an assurance that boiling of the cold reference column has not occurred, even under the worst possible drywell temperature conditions.

In the event of very rapid depressurization (such as during ADS operation), extensive reference column boiling could result in water level instrumentation readings being off-scale. (This would occur at low reactor vessel pressures and after all ECC systems performed their intended safety function following a small line break). This off-scale reading would persist until the reactor vessel water level returns to near normal following refilling of the reference column. Refilling of the reference column should occur in a very short time after LPCI system actuation.

A full size Yarway liquid level instrument column was tested by GE under simulated BWR loss-of-coolant accident conditions. The water level indicated by the Yarway column was compared with the water level measured with test instrumentation. It was found that the Yarway tracks a rapid level drop satisfactorily during a liquid blowdown situation. In the configuration tested (the test vessel was a 12-inch diameter pipe), the steam blowdown caused the Yarway to oscillate about the correct level as the level decreased in the test vessel. Instrument performance was not significantly affected by long instrument lines, flow check valves, additional indicators, and orifices placed in the instrument lines.

The actual level of water affects the absolute accuracy of measurement because density-dependent inaccuracies are proportional to the actual head of fluid above the lower instrument tap. Percentage of indicated differential pressure inaccuracies for levels at scale zero and above, and percentage of differential pressure range inaccuracies below scale zero are accounted for in the span and zero adjustments of the instruments.

For the BWR/3 through BWR/5 plants, the reactor jet pump flow in the annulus region outside the core shroud and past the lower tap of the wide range level instruments, has a significant velocity head and some friction loss which reduces the pressure on the variable leg to the differential pressure (level) instrument, resulting in an indicated level lower than actual. The effect of recirculation flow on reactor pressure vessel level measurement is limited to the wide range configuration in which the level instrument nozzle is near the top of the fuel. Accordingly, no effect on reactor pressure vessel level measurement for control (narrow range) level measurement exists, or for any measurements in the BWR/2 and BWR/3 plants, where the level instrument nozzle is well above the shroud head. The inaccuracy introduced by this flow varies approximately as the square of the reactor recirculation flow (velocity head). The friction component, which is small, varies approximately linearly with the flow rate. The combined inaccuracy from these factors depends on recirculation flow rate, area of the annulus, and location of the lower instrument tap. The range over all reactor types to which it applies is four to 18 inches.

This inaccuracy does not affect the low pressure (e.g., low pressure core spray) ECC initiation setpoint because the recirculation pumps are tripped before the level reaches the low pressure ECC setpoint. Scram setpoints are not affected because they are taken from the narrow range instruments, whose lower taps are above the influence of jet pump flow. Setpoints for HPCI/HCPS and RCIC system initiation have been established taking the recirculation flow effects into consideration. Because the effect results in a lower than actual indicated level, the HPCI/HPCS and RCIC systems will be started at higher actual levels with higher recirculation flows.

The pressure drop through the steam dryer assembly causes a depression in the level of water inside the shroud with respect to the water outside the shroud. This difference is a function of main steam flow squared and reaches a magnitude of from seven to 15 inches of reactor water (depending on plant product line) at full steam flow. This level relationship is taken into consideration in the setting of the reactor level control (feedwater control) setpoint and the alarm and safety trip setpoints above instrument zero.

The principal effects of power level on reactor pressure vessel level are results of varying dryer and separator pressure drop and feedwater flow dependent subcooling effects.

The steam separator pressure drop has no direct effect on level measurement because under normal operation, the steam separators are completely filled and dominated by recirculation flow. The interface between water and steam only exists outside the steam separators. This interface assumes a crowned configuration which varies somewhat with recirculation flow and power level (steam flow). This interface is not seen by the reactor pressure vessel water level sensors because they sense in the annulus region. Appropriate allowance for this difference is factored into the feedwater level control and the alarm and trip setpoints.

For all BWRs with jet pumps and for the Humboldt Bay plant (BWR/1), there is a simple, fully open link between water level outside the core shroud and the coolant mixture directly in and above the core. Unless the core becomes uncovered, there should be no significant fuel distortion, blockages or counter current flow problems which could increase core resistance enough to cause the outside shroud measurement to be nonrepresentative of level inside the core shroud. Likewise, there is a link between water level outside the core shroud and the coolant mixture in and above the core for the Dresden 1 and Big Rock Point plants and the BWR/2 plants provided that one or more recirculation lines are available for recirculation flow.

Even if the core becomes uncovered, there are multiple paths for water to enter the core and prevent significant fuel and bypass distortion. Therefore, the probability of high core resistance due to fuel failure and bypass distortion is very small.

Because of the fully open link between the water level outside the core shroud and the coolant mixture directly in and above the core for the Humboldt Bay plant and the jet pump plants; and because of the low probability of extensive (>90 percent) blockage inside the shroud; the outside shroud level measurements are considered to be reliable indicators of inside shroud level.

For the non-jet pump plants (other than the Humboldt Bay plant), a direct link between the outside shroud and inside shroud regions must be maintained by preventing closure of loop isolation valves in all of the recirculation loops. Therefore, interlocks must be installed in the non-jet pump plants (other than the Humboldt Bay plant) to insure that at least two recirculation loops are open for recirculation flow for modes other than cold shutdown.

A knowledge of mixture level in or above the core is essential for determining correct operator action during an event and for determining the severity of an event. If the core remains covered throughout a transient, then the level measurements outside the core shroud are reliable indicators of mixture level inside the core shroud and are useful for determining operator actions. If the core becomes uncovered for any significant time (to be defined by analysis), then the outside shroud level measurements (and any other level measurements based on differential pressure) are suspect and core cooling must be verified by other indicators; these may include incore detectors or area radiation monitors. Therefore, all BWR plants must have the capability to record vessel water level over a range extending from the top of the steam dome down to the elevation of the lowest pressure taps. This record should be available in a single location but multiple recorders may be used. The recorders should meet normal post-accident requirements. The recorders should be actuated on a reactor trip.

As typified in Figure A-19c, different level instruments have different reference points. These different reference points of the various level instruments may cause some operator confusion as to level above the core. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the fuel are reasonable reference points.

3. PLANT RESPONSE TO LOSS OF FEEDWATER EVENTS

3.1 Steady-State Operation

The BWR coolant system behavior during steady-state operation involves a balance of flow between the steam leaving the reactor vessel and the returning feedwater flow. The feedwater control system automatically controls the flow of feedwater into the reactor vessel to maintain the water in the vessel at a predetermined level during all modes of plant operation. The control water level is based on minimizing the carryover of water from the steam separators to prevent turbine blade erosion, and minimizing the carryunder of steam to prevent recirculation pump cavitation. For optimum limitation of carryover and carryunder, the steam separators require that the reactor vessel water level decrease as reactor power increases. This control must also account for normal swelling and shrinking of level which occurs on the raising and lowering of reactor power, respectively.

The reactor water level control system is a three-element control system which employs inputs from reactor vessel level, steam flow, and feedwater flow to maintain the desired level. At startup or low load, single-element control based on level only, may be selected.

Three-element control sums a steam flow/feed flow mismatch with the level error so that the system can take rapid action on transients to prevent a gross level change. In this scheme, if steam flow were to be cut off, the feedwater flow could be reduced to a minimum immediately without waiting for a level rise.

Final water level control is accomplished by taking the error signal generated by the control system and applying it to either a motor-operated regulating valve or to the turbine control system of a variable speed turbine-driven feedwater pump. By positioning the regulating valve or varying the speed of the turbine, the feedwater flow can maintain the level as required.

The reactor vessel water level is determined by one of two level sensors. Each sensor has its own separate vessel penetration and its own water density compensation by a vessel pressure sensor to assure accuracy during all conditions. Each level is displayed in the control room and either one may be selected for control system input and control room recording.

Feedwater flow is monitored by flow transmitters located on each feedwater line. These transmitters are density-compensated by measuring the temperature of the feedwater flow through the transmitter. The total feedwater flow is derived by summing the output of all flow signals.

Steam flow is monitored in each of the four steam lines by taking the differential pressure across the flow restrictor. The differential pressure is density-compensated by a pressure signal. The total steam flow is then derived by summing the steam flows of the four individual lines.

The total steam flow signal and total feedwater flow signal are then fed into a summer which outputs the mismatch between steam and feedwater flow. This mismatch gives the anticipatory response to level changes. This mismatch signal is summed with the actual level to form a corrected level for three-element control.

The manual/automatic transfer station is a manual controller with a transfer switch. When in automatic, the transfer switch is positioned so that the manual controller is bypassed and the error signal from the level controller is transmitted. During startup or when manual control is desired, the error signal from the level controller is blocked by the transfer switch and the feedwater control signal is transmitted and controlled by the operator.

3.2 Loss of Feedwater Event (Normal Case)

A loss of feedwater flow could occur from pump failures, feedwater controller failures, operator errors, or reactor system variables such as a high vessel water level trip signal. Following loss of feedwater flow, the reactor power starts to drop, the turbine control valves start to close to regulate pressure, the water inventory in the reactor vessel continuously decreases, and reactor scram occurs on a low vessel water level (Level 3) trip. Decay and stored heat continue to generate steam after the reactor scram, and the reactor vessel water inventory continues to decrease. For BWR/2 through BWR/5 plants, when the low-low vessel water level (Level 2) trip is reached, the recirculation pumps trip, all primary system isolation valves, including the MSIVs, receive a close signal, and high pressure cooling system operation is initiated (an applicable combination of the HPCS, HPCI, RCIC, and FWCI system, depending on plant vintage). The closure of the MSIVs causes the vessel pressure to rise to the lowest relief valve setpoints. The relief valves open automatically to relieve the overpressure. When the pressure drops below the reclosure setpoint, the relief valves close. The pressure relief valves will cycle open and closed as needed to relieve pressure at a decreasing rate as decay heat generation diminishes. The high pressure systems will maintain the water in the vessel at near normal levels with manual operator control. When the reactor presssure decreases to 150 psig, the operator can use the RHR system in the shutdown cooling mode or use the main condenser as a heat sink.

For BWR/1 through BWR/3 plants with isolation condensers, following MSIV isolation, the pressure rises to the setpoint initiation of the isolation condenser. The initial cold inventory from the isolation condenser causes a steep rise in reactor water level and a decrease in pressure. The operator manually cycles isolation condenser operation to maintain a vessel cooldown rate of less than 100 Fahrenheit degrees/hour. When the reactor pressure reaches 150 psig, the operator places the RHR system in the shutdown cooling mode and secures the operation.

The corrective functions for this event are automatic. The operator only performs a monitoring function to verify the following automatic actions: all control rods inserted after the scram, MSIV closure, high pressure cooling system initiation, self-actuation of relief valves on reactor high pressure, recirculation pump trip, and normal turbine coastdown. The operator may secure the high pressure systems when the reactor level and pressure are under control and the decay heat diminishes to the point where operation of the RHR system can be initiated.

This transient is most severe from high power conditions because the rate of reactor vessel level decrease is greatest and the amount of stored and decay heat to be dissipated are highest. The consequences of this event do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed.

3.3 Loss of Feedwater with a Stuck-Open Safety/Relief Valve

The initial phases of this event are similar to those described above for the normal loss of feedwater. The water inventory in the reactor vessel continuously decreases and reactor scrams on a low vessel water level trip (Level 3) occurs. Decay and stored heat continue to generate steam after the reactor scram and the reactor vessel water inventory continues to decrease.

When the low-low vessel water level (Level 2) trip is reached, for the BWR/2 through BWR/5 plants, the recirculation pumps trip. Isolation of the MSIVs occurs and an appropriate combination of the HPCS, HPCI, FWCI, and RCIC systems and startup of the low-pressure ECC system pumps are initiated. The closure of the MSIVs causes the vessel pressure to rise to the lowest relief valve setpoint group. The relief valves open automatically to relieve the overpressure. When the pressure decreases sufficiently, all but the stuck-open safety/relief valve will close and the high pressure system(s) will continue to provide makeup water. The other pressure relief valves will cycle open and closed as needed to relieve pressure, but not as frequently as for the normal loss of feedwater case due to the additional loss of energy through the stuck-open safety/relief valve. The reactor pressure and water level will continue to decrease and the high pressure systems will keep the core covered and cool the reactor down. Depending upon the high pressure systems available, the high pressure systems may cycle on and off betweeen Levels 2 and 8 to maintain reactor water at near normal operating level, or the operator may take manual control of the systems to maintain normal water level. When the reactor pressure decreases to 150 psig, the operator can switch to the RHR system shutdown cooling mode to achieve cold shutdown.

When the primary system level reaches the low level trip for BWR/1 plants, isolation occurs and the low pressure ECC system pumps start. The reactor pressure starts to rise and the isolation condenser is assumed not to operate at its initiating setpoint. The reactor pressure reaches the setpoint of the lowest relief valve which then opens. The pressure then decreases to the reclosure setpoint, however, the relief valve is assumed to fail to close. The reactor pressure continues to decrease due to the stuck-open safety/relief valve until the pressure decreases to the point where the low pressure ECC systems start injecting water into the reactor vessel. When the reactor pressure decreases to 150 psig the operator can use the RHR system in the shutdown cooling mode and control reactor water level by throttling the low pressure ECC flow.

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The corrective functions for this event are initially automatic and the operator only performs a monitoring function to verify the following automatic actions: all control rods inserted after the scram, MSIV closure, HPCI and RCIC system initiation, self-actuation of relief valves on reactor high pressure, recirculation pump trip, and normal turbine coastdown.

The operator may be able to determine that the safety/relief valve is stuck open from the following indications:

(1) High temperature indication in the safety/relief valve blowdown lines (however, temperatures may already be high from initial blowdown),
(2) Low reactor vessel level,
(3) Cycling on and off of high pressure injection systems,
(4) Continuing increase in suppression pool temperature, and
(5) Increase in suppression pool level.

The operator may secure the high pressure systems when the reactor level and pressure are under control and the decay heat diminishes to the point where operation of the RHR system can be initiated. The operator also continuously monitors the suppression pool temperature to determine when the service water temperature is exceeded. The RHR system pumps (if not needed in the low pressure coolant injection mode for maintaining vessel level) are used to cool the suppression pool in the suppression pool cooling mode. This transient is most severe from high power conditions because the rate of reactor vessel level decrease is greatest and the amount of stored and decay heat to be dissipated are highest. The consequences of this event do not result in any temperature or pressure in excess of the criteria for which the fuel, pressure vessel, or containment are designed.

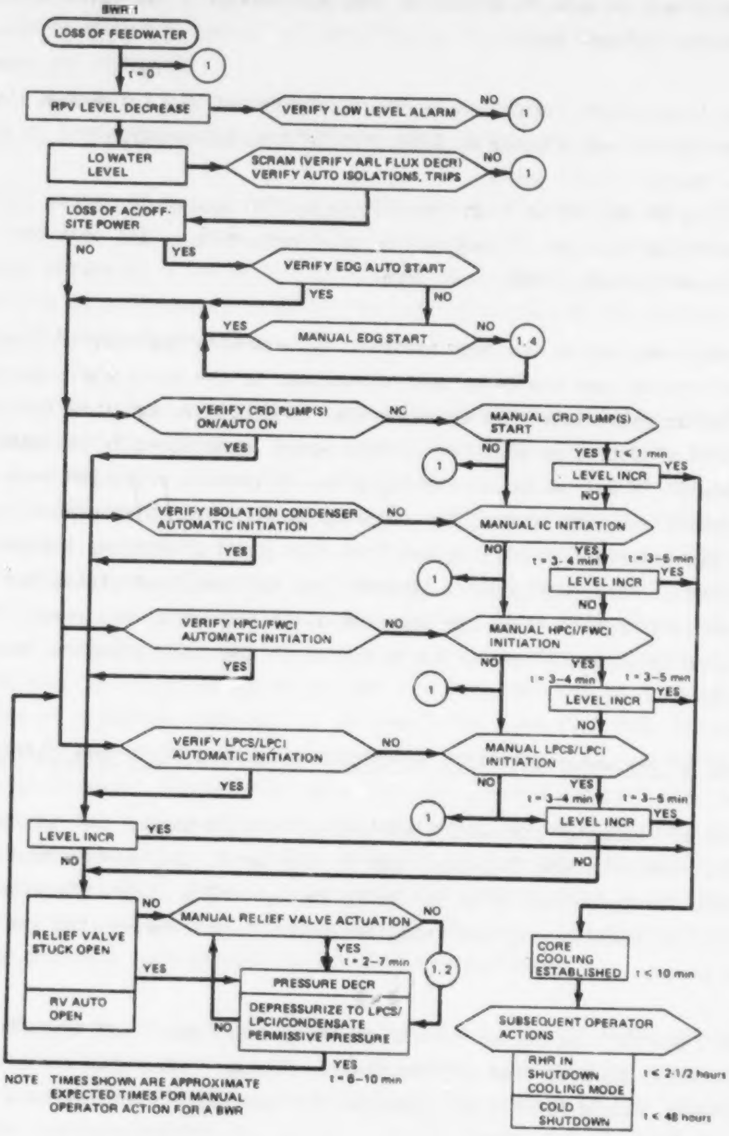
3.4 Loss of Feedwater with Loss of Offsite Power and Stuck-Open Safety/Relief Valve

On a loss of feedwater combined with loss of offsite power, the reactor will scram. Following reactor scram this transient is similar to the loss of feedwater event with stuck-open safety/relief valve for BWR/2 through BWR/5 plants (Section 3.3) since none of the ECC or auxiliary systems required to maintain core cooling are powered from offsite power.

For BWR/1 plants, the backup systems to the ECC and auxiliary support systems are in some instances powered from offsite power. However, even with these systems unavailable, these plants should be able to maintain core cooling and achieve cold shutdown.

Using the safety grade systems available (see Figure A-21) for the Dresden 1 plant, the combination of the isolation condenser and HPCI system currently being installed should depressurize the reactor to a pressure where the system LPCS can be initiated. For the Humboldt Bay and Big Rock Point plants, the ADS should depressurize the reactor to a pressure where the LPCS system can be initiated. When the reactor level and pressure are under control and the decay heat diminishes, the operator can initiate operation of the RHR system to achieve cold shudown.

Figure A-21


BWR 1
LOSS OF FEEDWATER
t = 0
1
RPV LEVEL DECREASE
VERIFY LOW LEVEL ALARM
NO
LO WATER LEVEL
SCRAM (VERIFY ARL FLUX DECR) VERIFY AUTO ISOLATIONS, TRIPS
LOSS OF AC/OFF-SITE POWER
YES
VERIFY EDG AUTO START
MANUAL EDG START
1, 4
VERIFY CRD PUMP(S) ON/AUTO ON
MANUAL CRD PUMP(S) START
t ≤ 1 min
LEVEL INCR
VERIFY ISOLATION CONDENSER AUTOMATIC INITIATION
MANUAL IC INITIATION
t = 3-4 min
t = 3–5 min
VERIFY HPCI/FWCI AUTOMATIC INITIATION
MANUAL HPCI/FWCI INITIATION
VERIFY LPCS/LPCI AUTOMATIC INITIATION
MANUAL LPCS/LPCI INITIATION
RELIEF VALVE STUCK OPEN
RV AUTO OPEN
MANUAL RELIEF VALVE ACTUATION
t = 2–7 min
1, 2
PRESSURE DECR
DEPRESSURIZE TO LPCS/LPCI/CONDENSATE PERMISSIVE PRESSURE
t = 6–10 min
CORE COOLING ESTABLISHED
t < 10 min
SUBSEQUENT OPERATOR ACTIONS
RHR IN SHUTDOWN COOLING MODE
t ≤ 2-1/2 hours
COLD SHUTDOWN
t < 48 hours

NOTE TIMES SHOWN ARE APPROXIMATE EXPECTED TIMES FOR MANUAL OPERATOR ACTION FOR A BWR

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Figure A-21 Operator Action Scenario (BWR/1 Plants)

3.5 Loss of Feedwater with Loss of Onsite Power and Stuck-Open Safety/Relief Valve

On loss of feedwater combined with loss of onsite power, the reactor will scram and the recirculation pumps will trip. Decay and stored heat continue to generate steam after reactor scram and the reactor vessel water inventory continuously decreases.

For BWR/3 through BWR/5 plants, when the low-low vessel water level (Level 2) trip is reached, all primary system isolation valves, including the MSIVs, receive a close signal and high pressure cooling system operation is initiated. No low-pressure ECC system will start due to the loss of all alternating current power. The closure of the MSIVs causes the vessel pressure to rise to the lowest relief valve setpoints. The relief valves open automatically to relieve the overpressure. When the pressure drops below the reclosure setpoint, all the valves are assumed to close with the exception of one which is assumed to be stuck open. The other pressure relief valves will cycle open and closed as needed to relieve pressure but not as frequently as if the safety/relief valve were not stuck open. Loss of offsite power resulting from the failure of the diesels to start does not affect the operation of the high pressure systems on (a) BWR/2 through BWR/4 plants which have steam-driven HPCI and RCIC system, (b) BWR/1 through BWR/3 plants which have isolation condensers, and (c) BWR/5 plants which have RCIC systems. However, the HPCS and FWCI systems will not be available. The reactor pressure and water level will continue to decrease, and the high pressure systems will keep the core covered and cool the reactor. The high pressure systems may cycle on and off between Levels 2 and 8 to maintain reactor water at near normal operating level. When the reactor pressure reaches 150 psig, the turbine will trip on low reactor pressure. If onsite or offsite alternating current power has not been restored by this time, the water remaining in the vessel will start to boil off and core uncovery will start to occur. If power is not restored and makeup water provided, the core will start to heat up as it becomes uncovered, and extensive core damage will result.

For BWR/1 and BWR/2 plants which do not have a steam-driven HPCI system, after MSIV closure, the reactor pressure will start to rise and the isolation condenser is assumed not to operate at its initiating setpoint. The reactor pressure reaches the setpoint of the lowest relief or safety valve which then opens. After the safety/relief valve lifts, it is assumed the operator opens the isolation condenser. The pressure then decreases to the reclosure setpoint, however, the relief valve fails to close. The water supply on the shell side of the isolation condenser will provide a heat sink for cooling for a minimum of 40 minutes before makeup is required. However, due to the stuck-open safety/relief valve, the water level in the reactor vessel will continue to decrease and core uncovery will start to occur. If power is not restored and makeup water provided, the core will start to heat up as it becomes uncovered and extensive core damage will result.

This transient is most severe from high power conditions because the rate of reactor vessel level decrease is greatest and the amount of stored and decay heat to be dissipated are highest.

Since a loss of feedwater event with a loss of onsite alternating current power (station blackout) can lead to unacceptable consequences, we recommend that the utilities perform analyses, on a plant-specific basis, to determine the plant capability to adequately cool the reactor under these conditions. Times to core uncovery and core damage should also be determined. The equipment and instrumentation available and the operator actions to be performed under these conditions to mitigate the consequences of this event should be identified.

APPENDIX B

BWR PLANT OPERATIONS

1. SURVEY OF FEEDWATER-RELATED EVENTS

At our request, each BWR licensee provided information pertaining to all events that resulted in a complete loss of main feedwater over the last three years of operation. For each event, available data on the initiating circumstances, consequences, and any unusual conditions are summarized briefly.

1.1 Duane Arnold

(1) On 8/12/76, at 73 percent power, an electro-hydraulic controller malfunction caused a reactor pressure change resulting in a high flux transient. The feedwater pumps tripped on high reactor water level (+53 inches). The pumps were manually restarted.

(2) On 11/1/77, at 100 percent power, an erroneous high water level signal during instrument calibration caused turbine trip and feedwater pump trip which resulted in a reactor scram, Group 1 isolation, and SRV activation.

(3) On 1/10/78, at 38 percent power, a feedwater regulating valve response problem during a power decrease caused a high reactor water level (+53 inches) trip of the feedwater pumps. The feedwater pumps were manually restarted.

(4) On 7/18/79, at 95 percent power, a turbine trip on high exhaust temperature occurred. Due to slow feedwater regulator response, low-low level, Group 1 isolation occurred, followed by high water level (+53 inches), causing the feedwater pumps to trip. The pumps were manually restarted.

1.2 Big Rock Point

(1) On 4/6/78, at 89 percent power, the reactor tripped on loss of the 138-kV line due to a defective telephone company cable utilized for the tone relaying transmission system protective equipment. Load rejection was not effective resulting in a condenser loss of vacuum and high hotwell level. Loss of feedwater occurred due to either feedwater pump trip due to low suction pressure during condensate reject or station power feed transfer to the 46-kV Charlevoix Line. Steam drum level fell rapidly. Two level sensors for low steam drum level at minus eight inches below center line operated within two seconds following the reactor trip on condenser low vacuum. One main feedwater pump was restarted manually within first few minutes.

(2) On 5/31/78, at 86 percent power, the reactor tripped due to wiring errors on protective relaying at an offsite substation. This was essentially a repeat of the 4/6/78 incident; however, documentation of complete loss of main feedwater is not available. A repeat of the previous transient can be assumed.

1.3 Browns Ferry 1

(1) On 2/11/77, at 96 percent power, the reactor feedwater pump turbines (RFPTs) tripped on high vessel water level due to a control malfunction caused by operator error. The main steam line relief valves (MSRVs) lifted. The MSIVs closed. The HPCI and RCIC systems initiated. Normal feedwater flow was restored.

(2) On 4/28/77, at 83 percent power, the RFPTs tripped on a false high water level signal due to electrical power loss. Normal feedwater flow was restored.

(3) On 6/7/78, at 95 percent power, the RFPTs tripped on false high vibration signals due to low voltage. The MSIVs closed, MSRVs opened, and normal feedwater flow was restored.

(4) On 7/9/78, at 94 percent power, the RFPTs tripped on false high vibration signals due to low voltage. The MSIVs closed, MSRVs opened, and normal feedwater flow was restored.

(5) On 8/11/78, at 89 percent power, the RFPTs tripped on false reactor high water level due to electrical power loss. The MSIVs closed, MSRVs opened, and normal feedwater flow was restored.

(6) On 4/29/79, at 99 percent power, the RFPTs tripped on false high water level due to electrical power loss. The MSIVs closed, MSRVs opened, the RCIC system initiated, and normal feedwater flow was restored.

(7) In addition, there were two instances where the MSIVs closed, as designed, upon reactor scram which resulted in momentary feedwater interruption which was restored in three to five minutes. These are not tabulated separately.

1.4 Browns Ferry 2

(1) On 10/17/77, at 93 percent power, the RFPTs tripped on a false high vibration signal (low voltage). The MSRVs lifted, MSIVs closed, the HPCI and RCIC systems maintained water level, and normal feedwater flow was restored.

(2) On 7/9/78, at 58 percent power, the RFPTs tripped on a false high vibration signal (low voltage). Normal feedwater flow was restored.

(3) In addition, there were three instances where the MSIVs closed, as designed, upon reactor scram which resulted in momentary feedwater interruption which was restored in three to five minutes. These are not tabulated separately.

1.5 Browns Ferry 3

(1) On 6/26/78, at 96 percent power, the RFPTs tripped on false high reactor water level signal. The MSRVs opened, MSIVs closed, and normal feedwater flow was restored.

(2) In addition, there were 18 instances where the MSIVs closed, as designed, upon reactor scram which resulted in momentary feedwater interruption which was restored in three to five minutes. These are not tabulated separately.

1.6 Brunswick 1

(1) On 1/17/77 with the reactor power at 66 percent, the station battery chargers were placed in the equalize mode to raise the batteries' specific gravities. The direct current to alternating current topaz inverters which supply control power for the feedwater control, HPCI and RCIC system, and steam leak detection systems tripped on high direct current voltage from the batteries. Two control rod drive pumps were utilized to maintain reactor vessel water level. It was found that the direct current voltage setpoints on the inverters had been improperly set.

(2) On 9/16/77, with the reactor power at 99.8 percent, repacking of IC condensate pump was started with the suction valve open. When the last ring of the old packing was removed, air was sucked in to the condensate pump suction header (30-inch main condenser vacuum). This caused the two running condensate pumps to cavitate. The condensate booster pumps tripped on low suction pressure and the reactor feedwater pumps tripped on low suction pressure. The reactor scrammed on low level and normal recovery procedures were followed.

(3) On 4/30/78, with the reactor power at 100 percent, the reactor feedwater pump 'B' lube oil strainers were being shifted. When the shift was performed, an air pocket went through the oil piping and the feedwater pump tripped on low oil pressure. Normal scram recovery procedures were followed.

1.7 Brunswick 2

(1) On 11/2/76, with reactor power at six percent with a reactor startup in progress, condensate filters and demineralizers were being placed in service when the condensate booster pumps tripped on low suction pressure. The condensate discharge pressure had been normal; therefore, restriction of flow due to a valve drift was suspected. Several attempts were made to start the RCIC system but high exhaust pressure trips prevented it from operating. The HPCI system was started and the subsequent cold slug caused a scram on average power range monitors (APRMs) at 15 percent power.

(2) On 12/18/76, with the reactor power at 63 percent with 2A reactor feedwater pump (RFP) running and 2B RFP under clearance for maintenance, the 2A RFP oil strainer

plugged causing the feedwater pump to trip on low oil pressure followed by a scram from reactor low level.

(3) On 2/23/77, with the reactor power at 64 percent, in the process of bringing on the 2B RFP, the 2A RFP tripped on low suction pressure. A scram followed due to reactor low water level. Investigation revealed the low suction pressure trip setpoint on the 2A RFP was at 180 psig instead of 30 psig as called for by calibration data.

(4) On 4/5/77, with the reactor power at 70 percent, the radwaste instrument air header was shifted over to be supplied from Unit 2. The Unit 2 supply header check valve was stuck. The Unit 2 CFD and CDD valves cycled closed and the condensate booster pumps and feedwater pumps tripped on low suction pressure. The reactor scrammed on low reactor water level.

(5) On 5/7/77, with the reactor power at 30 percent with the 2A feedwater pump on line in automatic, an attempt was made to bring on the 2B feedwater pump. When the 2B feedwater pump was placed in automatic, the vessel water level started decreasing. A reactor scrammed on low level. Investigation revealed the condensate deep-bed demineralizer master flow controller was in manual. This would cause the differential pressure to increase and open the bypass valve, but the bypass valve controller was found to be in manual-shut. The increased flow from placing the second RFP in service caused the differential pressure to increase which meant a lower suction pressure on the condensate booster pumps and feedwater pumps causing them to trip.

(6) On 6/14/77, with the reactor power at 83 percent, a power increase had just been completed and oscillations in the feedwater heater heater levels and heater drain deaerator level were observed. The condensate deep-bed demineralizer outlet valves failed and tripped the booster pumps and feedwater pumps on low suction pressure. The reactor scrammed on low water level.

(7) On 3/23/78, with the reactor power at 96 percent, a high reactor water level alarm and a spike increase in feedwater flow was noted. The 2B RFP was operating at 3000 RPM and the 2A RFP was operating at 6000 RPM. This was actually a failure of the 2A RFP control in the high direction rather than a loss of feedwater. The high water level tripped both feedwater pumps and the reactor then scrammed on low water level.

1.8 Cooper

On 8/9/79, at 99 percent power, the condensate pump suction boot failed. The condensate booster pump tripped, causing both reactor feedwater pumps to trip. The reactor scrammed and the MSIVs closed on low water level. Two SRVs lifted automatically; three were later lifted to control pressure.

1.9 Dresden 1

The Dresden 1 plant has experienced no events resulting in a complete loss of feedwater in the last three years of operation.

1.10 Dresden 2

The Dresden 2 plant has experienced no events resulting in a complete loss of feedwater in the last three years of operation.

1.11 Dresden 3

The Dresden 3 plant has experienced no events resulting in a complete loss of feedwater in the last three years of operation.

1.12 FitzPatrick

(1) On 12/12/78, when transferring from single-element feedwater control to three element control, the feedwater pump went to runout and subsequently tripped on high reactor water level. The cause of the feedwater pump going to runout was improper replacement of leads on three-element controller following maintenance. With loss of feedwater to the reactor vessel, a reactor scram occurred at the low water level trip point. Initial power level was 15.8 percent. The RCIC and HPCI systems initiated at low reactor water level and procedures for scram were carried out. Leads on the three-element controller were placed on the proper terminals and all superintendents were cautioned by the resident manager to assure that all electrical leads to be removed are marked properly and operability or visual checks are performed prior to returning the equipment to service.

(2) On 4/29/78, the reactor scramed from 12 percent power due to loss of feedwater flow while operating with one feedwater pump. After discovering water in the discharge pressure switch of the non-operating feedwater pump, the suction pressure switch of the operating feedwater pump was vented by mistake. Actions for a reactor scram were carried out and the RCIC system was initiated to maintain reactor water level.

1.13 Hatch 1

(1) On 5/22/77, at 21 percent power, one reactor feedwater pump stopped due to a loss of electrical power to the 4160-volt Bus 1D while transferring house loads to the main generator on the 1C 4160-volt bus. This resulted in a reactor low water level scram without HPCI or RCIC system initiation.

(2) On 5/24/77, at 39 percent power, a condensate booster pump tripped due to a clogged pump suction strainer which caused the reactor feedwater pumps to stop, resulting in a reactor scram without HPCI or RCIC system initiation.

(3) On 8/13/77, at 23 percent power, reactor feedwater pump 1A stopped due to low suction pressure of unknown origin. The reactor scrammed due to low water level without HPCI or RCIC system initiation.

(4) On 8/26/78, at 21 percent power, reactor feedwater pump 1B tripped while trying to start pump 1A resulting in a reactor low level scram. The HPCI system was initiated.

1.14 Hatch 2

(1) On 10/7/78, at 19 percent power, the RFPT tripped due to operator initiated turbine trip due to main turbine rubbing. Condenser vacuum had to be broken due to a high turbine vibration which caused the RFPT to trip due to a loss of condenser vacuum as required. The RCIC system tripped due to unknown reasons after being initiated by the operator. The reactor scrammed on low water level from the RFPT trip.

(2) On 10/21/78, at 34.7 percent power, RFP 2B tripped on low suction pressure due to operating personnel valving in the 10th stage heater with it not being filled completely. The reactor scrammed on a low water level with no HPCI or RCIC system initiation.

(3) On 11/2/78, at 19.8 percent power, RFP A tripped due to a condensate booster pump trip which was a result of test shop personnel improperly performing calibration on GEMAC level instruments 2C32-R606A, B, C, while feedwater pump A was in A level control. There was a low level scram with no HPCI or RCIC system initiation.

(4) On 12/8/78, at 66.3 percent power, placing the station batteries on overcharge caused an overvoltage trip on the static inverter feeding B reactor level, feedwater flow, steam flow, and reactor pressure instrumentation inputting to the feedwater controller. This caused an RFPT runout and booster pump trip which resulted in a reactor scram on low water level with no HPCI or RCIC system initiation.

(5) On 2/2/78, at 18.7 percent power, an inadvertent trip of 2C condensate booster pump tripped the RFP and caused a reactor scram on low level with no initiation of HPCI or RCIC systems.

(6) On 2/7/78, at 96.1 percent power, RFPT 2B was tripped per a startup test procedure. Condensate booster pump 2A tripped resulting in a trip of RFPT 2 which caused a reactor scram on low level with no initiation of HPCI or RCIC systems.

(7) On 6/3/79, at 92 percent power, 2A condensate booster pump tripped on low suction pressure causing the reactor to scram later on low water level. The RCIC system failed to start. The HPCI system started but the HPCI system stop valve would not open and the feedwater system was used to maintain the vessel level.

1.15 Humboldt Bay

In the most recent three years of operation (through July 1976), the Humboldt Bay plant has experienced no complete loss of feedwater events.

1.16 Millstone 1

On 8/10/76, the passing of Hurricane Belle caused a loss of normal alternating current power. At that time, the gas turbine was also unavailable making the feedwater system unavailable. The isolation condenser, diesel generator, and the control rod drive systems were used for heat removal and level control. The gas turbine was restored in 2½ hours and the feedwater system was then available.

1.17 Monticello

(1) On 2/23/77, at 100 percent power, there was a load rejection scram and RFP trip on loss of offsite power. The HPCI and RCIC systems started to control pressure and level, offsite power was restored, the RFP restored, and the RCIC and HPCI systems were shut down.

(2) On 3/28/79, at 62 percent power, there was a reactor scram due to a RFP trip on low suction pressure. The recirculation valve linkage problem caused the valve to open approximately 25 percent. The RFP was restarted to control level.

(3) On 7/20/79, at 100 percent power, there was a reactor scram on low level, following a loss of feedwater due to RFP trip on low suction. A master controller failure occurred. One RFP was restarted to control level.

(4) On 7/22/79, at 96 percent power, there was a reactor scram on low level due to the master controller failing closed. Valves were manually operated from the control room.

1.18 Nine Mile Point 1

The Nine Mile Point 1 plant has had no complete loss of main feedwater in the last three years of operation.

1.19 Oyster Creek

On 5/2/79, at 98 percent power, a pressure spike on reactor high pressure scram switches caused a reactor scram. A complete loss of feedwater led to decreasing reactor water level. An operator manually initiated MSIV closure and isolation condenser operation was initiated. However, because of closed recirculation line discharge valves on all five loops, reactor triple low water level was reached at about three minutes. Reactor level was recovered when a feedwater pump and a recirculation pump were restarted at about 40 minutes.

1.20 Peach Bottom 2

(1) All transients in which the MSIVs closed resulted in total loss of feedwater since the feedwater pumps are steam-driven. These are not separately tabulated.

(2) There were no other transients involving a total loss of feedwater in the past three years of operation.

1.21 Peach Bottom 3

(1) On 8/9/78, at 100 percent power, the master feedwater controller failed causing low level reactor scram. The MSIVs closed, four MSRVs opened and closed automatically, and the HPCI and RCIC systems automatically initiated. The HPCI system did not deliver full flow during this transient.

(2) On 8/24/78, at 100 percent power, the master feedwater controller failed causing a low level reactor scram. The MSIVs closed, the HPCI and RCIC systems initiated, and two MSRVs operated.

(3) On 11/6/78, at 100 percent power, the master feedwater controller failed causing a low level reactor scram. The MSIVs closed and the RCIC system automatically initiated. The HPCI system failed to operate. One relief valve opened automatically and three relief valves were manually operated.

(4) On 1/28/79, at 100 percent power, a blown fuse in the master feedwater controller caused a low level reactor scram. The MSIVs closed and the HPCI and RCIC systems and MSRVs were used to control reactor pressure and level.

(5) Any transient in which the MSIVs closed resulted in a total loss of feedwater since the feedwater pump turbines are steam-driven. These are not separately tabulated.

1.22 Pilgrim

(1) On 1/6/76, at 35.6 percent power, there was leakage in the feedwater system through the startup feedwater regulator which was broken due to violent vibrations caused by malfunctions of the B flow control valve. This forced the shutdown of all reactor feedwater pumps. The unit was shut down and cooled down. Water level was maintained using the control rod drive system and the RCIC system.

(2) On 5/1/77, at 100 percent power, there was a full load rejection and loss of offsite power due to a forest fire with consequent loss of all reactor feedwater pumps. The unit was shut down and cooled down. Water level was maintained using the control rod drive and RCIC systems.

(3) On 5/10/77, at 68.5 percent power, a violent sleet storm caused loss of offsite power with consequent loss of all reactor feedwater pumps. The unit was shut down and cooled down. Water level was maintained using the control rod drive and RCIC systems.

(4) On 11/17/77, at 20 percent power, there was a reactor low water level scram due to high differntial pressure across the condensate demineralizers, caused by failure of the internal laterals in the demineralizers, resulting in forced shutdown of all reactor feedwater pumps. Vessel level was maintained with the control rod drive and RCIC systems.

(5) On 11/17/77, with the unit shut down and the reactor at 400 psig, there was a reactor low water level scram due to failure of condensate demineralizers laterals requiring shutdown of reactor feedwater pump. Vessel level was maintained with the control rod drive and RCIC systems.

(6) On 12/9/77, at 3.5 percent power and 750 psig reactor pressure, there was a reactor low water level scram due to plugging of the condensate pump suction strainers with a resultant low suction pressure trip of the reactor feedwater pump. The HPCI system was used to recover the water level.

(7) On 2/6/78, at 25 percent power, there was a full load rejection with concurrent loss of offsite power caused by a severe snow storm with the consequent loss of all reactor feedwater pumps. Vessel level was maintained using the CRD and RCIC systems.

(8) On 8/6/78, at 100 percent power, there was a loss of offsite power due to a violent electrical storm. Lightning struck the high line, triggering protective relay operation. Loss of power initiated loss of all reactor feedwater pumps and the unit was shut down.

(9) On 7/27/79, at 100 percent power, there was a loss of power due to a severe electrical storm. Lightning struck the switchyard triggering protective relay operation. Loss of offsite power resulted in loss of all reactor feedwater pumps. Water level was maintained with the CRD and RCIC systems.

1.23 Quad Cities 1

(1) On 11/6/77, at 55 percent power, a severe electrical fault caused an undervoltage on the 4-kV buses and resulted in the scram of both reactors. The RCIC and HPCI systems were used to maintain reactor water level. One relief valve was operated manually to maintain pressure.

(2) On 2/19/78 during startup in intermediate range monitor (IRM) ranges 8 and 9, system voltage dropped to approximately 330-kV. The transformer feed to the buses was lost and the diesel-generator started. Normal auxiliary power was lost and the reactor scrammed. Normal auxiliary power was restored to the buses and it was not necessary to use the RCIC or HPCI systems to maintain reactor water level. The control rod drive system provided adequate water. No relief valves lifted.

1.24 Quad Cities 2

On 11/6/77, at 77 percent power, a severe electrical fault caused an undervoltage on the 4-kV buses and resulted in the scram of both reactors. The RCIC and HPCI systems were used to maintain reactor water level. One relief valve opened automatically and one was operated manually to maintain pressure.

1.25 Vermont Yankee

On 6/16/76, while operating at a normal steady-state power level of 88 percent, an operator mistakenly opened a reference leg isolation valve for reactor vessel level instrumentation believing it to be a supply of demineralized water. The level control system responded by ramping shut both feedwater regulating valves resulting in a low level scram within 12 seconds. Station electrical loads failed to automatically transfer to the startup transformer and a complete loss of normal electrical power resulted. In response, the HPCI and RCIC systems automatically started 17 seconds after the scram on receipt of a valid low-low vessel water level signal. Station operators implemented the loss-of-normal-power emergency procedure. The HPCI system was operated in the injection mode until vessel level returned to ten inches. At that time, a HPCI system flow test mode was implemented to establish a heat sink for the reactor decay heat. The RCIC system was operated throughout the transient for supplemental vessel level control.

2. SUMMARY OF BWR EXPERIENCE WITH SAFETY/RELIEF VALVES

Failure of the power-operated relief valve to reclose during the TMI-2 accident resulted in serious damage to the reactor core. As a consequence, relief valves in all plants, including BWRs, are being examined with a view toward their possible role in a small-break LOCA.

2.1 Design

All light water water reactors are required to have some means of relieving primary reactor coolant system pressure in order to prevent overpressurization. This protection takes the form of pressure relief valves which are set to open when the primary system pressure reaches the valve's setpoint. Early BWR plants (Nine Mile Point, Oyster Creek, Dresden, 2-3, and Quad Cities 1-2) use two separate types (see Table B-1) of valves for pressure relief -- relief valves and safety valves. The safety valves were used in analysis of overpressurization events to limit the pressure to 110 percent of design as required by the ASME Boiler and Pressure Vessel Code. Relief valves, on the other hand, were not considered in the mitigation of overpressure events. They were used as an operational convenience to avoid plant trip and consequent plant shutdown in the event of a partial load rejection event and to avoid the use of safety valves insofar as possible so that safety valves would be exercised only in the event of a severe transient. Because of this dual purpose, safety valves and relief valves were required to conform to different criteria. Safety valves had to operate reliably in order to perform satisfactorily when needed, while the reliability of relief valves was left to the discretion of the licensee. The portions of both safety and relief valves forming the primary system boundary, nevertheless, had to conform to identical, stringent criteria in order to minimize possible rupture of this boundary. It was only in the instrumentation and control system where differences were permitted and where safety criteria for such systems differed. For safety valves, stringent criteria were required for any auxiliary systems used for valve motivation. For relief valves, the licensees were allowed to use their own commercial criteria. Parenthetically, it must be noted that safety valves used in BWR plants do not use auxiliary systems for their actuation.

Pressure relief systems in later BWR plants use one type of valve, a safety/relief valve (SRV) for both functions. The quality of the instrumentation and controls utilized for the relief function were determined by the licensee while the valve itself had to conform to the safety criteria required by the NRC. Typical of these plants are Browns Ferry 1-3 and Brunswick 1-2. Note that while some of these later plants also employ separate safety valves, some do not. Also some of the plants (Dresden 2-3 and Quad Cities 1-2) which use separate relief valves and safety valves also use one SRV. Six plants (Nine Mile Point, Oyster Creek, Dresden 1-2, and Quad Cities 1-2) use electromatic relief valves manufactured by the Dresser Company; the SRVs are manufactured by Target Rock.

TABLE B-1

BWR PLANT PRESSURE RELIEF VALVE COMPLEMENTS

BWR Type	Facility	Safety/Relief Valves	Safety Valves	Power-Actuated Relief Valves
2	Nine Mile Point	-	16	6
2	Oyster Creek	-	16	5
3	Dresden 2	1	8	4
3	Dresden 3	1	8	4
3	Millstone 1	6	-	-
3	Monticello	7	-	-
3	Pilgrim 1	4	2	-
3	Quad Cities 1	1	8	4
3	Quad Cities 2	1	8	4
4	Browns Ferry 1	11	2	-
4	Browns Ferry 2	11	2	-
4	Browns Ferry 3	11	2	-
4	Brunswick 1	11	-	-
4	Brunswick 2	11	-	-
4	Cooper	8	3	-
4	Duane Arnold	6	2	-
4	FitzPatrick	11	-	-
4	Hatch 1	11	-	-
4	Peach Bottom 2	11	2	-
4	Peach Bottom 3	11	2	-
4	Vermont Yankee	4	2	-
4	Hatch 2	11	-	-

Some plants (BWR/1s), not shown on Table B-1 (Big Rock Point and Humboldt Bay) have pressure relief systems employing only spring-loaded safety valves; there is no separate relief function for operational convenience. Dresden 1, a BWR/1 type plant, does have two relief valves but they are located outside of primary containment and are ineffective for primary system pressure relief for any event resulting in primary system isolation. For all three plants, there is only one event reported (at the Big Rock Point plant) which required pressure relief--an overfilling during startup resulting in opening of a spring-loaded safety valve with no valve failure. Because their pressure relief systems are different from those in the other plants and because no problems have been experienced, these plants do not enter into the discussion of concern with pressure relief valves.

In addition to the relief function and safety function, most BWR plants require these valves (safety, relief, and SRV) to perform still another function; i.e., automatic depressurization. Automatic depressurization of the primary system is required in the event of a small-break LOCA where the system pressure remains high and the plant has no high pressure ECC system capable of injecting water into the system to cool the core, either as a result of high pressure ECC system failure or because the plant has no system available. For plants with high pressure ECC systems, the ADS operates only in the event of failure of the high pressure ECC system. For plants without a high pressure ECC system, the ADS system actuates to reduce primary system pressure to allow core cooling by means of low pressure cooling systems. Generally, in the older plants, the ADS system uses electromatic relief valves while the newer plants use a number of the SRVs for the ADS function.

The separate relief valves used in the earlier plants noted above were power-actuated valves manufactured by the Dresser Company, commonly known as "electromatic" valves (shown in Figure B-1). These valves should actually be termed solenoid-operated power-actuated relief valves since they operate as follows: System steam at pressure is applied to the main disk at the valve inlet (Chamber A), passing upward around the disc guide in Chamber B, also entering Chamber C through a clearance space between the main valve and disc and disc guide. The main valve disc is held against the seat, in the closed position, by the steam pressure in Chamber C. Actuation is accomplished by energizing the solenoid assembly which then moves the pilot operating lever, moving the pilot valve disc and allowing steam from Chamber C to escape, reducing the pressure in Chamber C. The resulting differential pressure on the main valve disc causes it to open, allowing steam to escape from Chamber B to the outlet of the valve.

SRVs in the operating plants are usually three-stage Target Rock valves (Figure B-2). In either the ADS mode or relief mode, air or nitrogen is admitted to the chamber above the air actuator. This differential pressure drives the actuator downward, moving the second stage piston spring and disc downward, thereby unseating the second stage disc. This action relieves the pressure from above the main valve piston with system pressure acting both to force the main valve disc down against the seat and to force the main valve piston upward. Since the diameter of the piston is greater than

Figure B-1

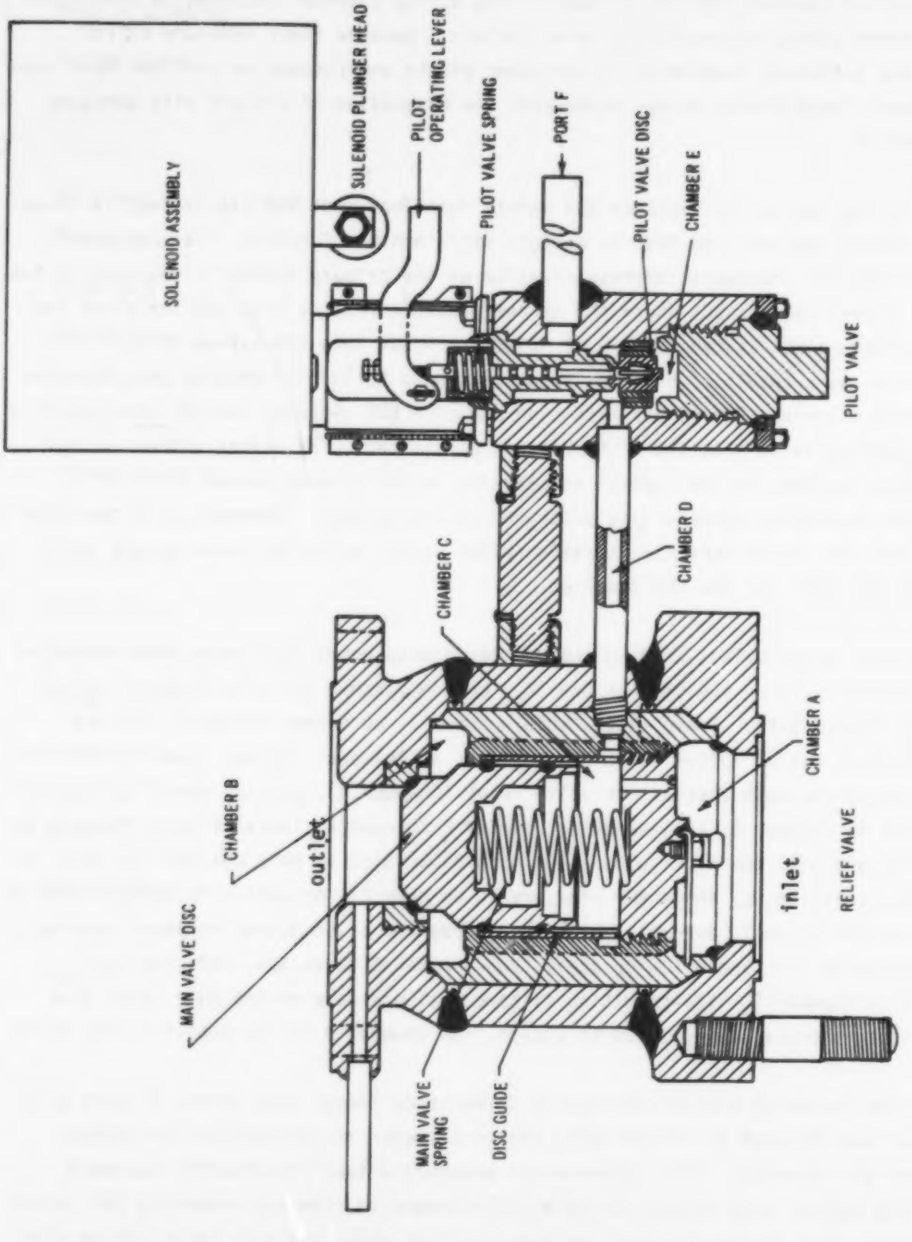
SOLENOID ASSEMBLY
SOLENOID PLUNGER HEAD
PILOT OPERATING LEVER
PILOT VALVE SPRING
PORT F
PILOT VALVE DISC
CHAMBER E
PILOT VALVE
CHAMBER D
CHAMBER C
CHAMBER B
outlet
MAIN VALVE DISC
CHAMBER A
inlet
RELIEF VALVE
MAIN VALVE SPRING
DISC GUIDE

Figure B-1 Power Actuated Relief Valve

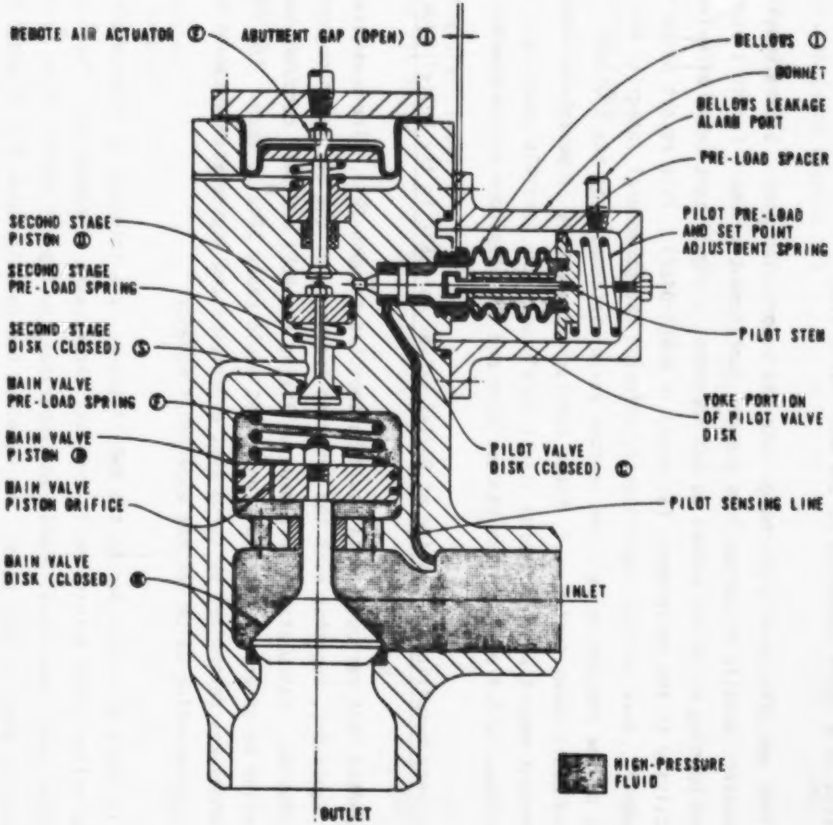
REMOTE AIR ACTUATOR
ABUTMENT GAP (OPEN)
SECOND STAGE PISTON
SECOND STAGE PRE-LOAD SPRING
SECOND STAGE DISK (CLOSED) ⑤
MAIN VALVE PRE-LOAD SPRING
MAIN VALVE PISTON
MAIN VALVE PISTON ORIFICE
MAIN VALVE DISK (CLOSED)
BELLOWS ①
BONNET
BELLOWS LEAKAGE ALARM PORT
PRE-LOAD SPACER
PILOT PRE-LOAD AND SET POINT ADJUSTMENT SPRING
PILOT STEM
YOKE PORTION OF PILOT VALVE DISK
PILOT VALVE DISK (CLOSED)
PILOT SENSING LINE
INLET
OUTLET
HIGH-PRESSURE FLUID

Figure B-2 Three-Stage Pilot-Operated Pressure Relief Valve that of the disc, the net force is upward, opening the valve. Self-actuation occurs when sufficient system pressure enters the pilot sensing port to cause the bellows to expand. This eliminates the abutment gap, pulling the pilot disc from its seat and allowing system pressure to enter the volume above the second stage piston forcing the second stage piston down. This action unseats the second stage disc thereby relieving system pressure above the main valve piston and opening the valve.

SRVs in more recent plants (not yet licensed), use direct system pressure against a spring-loaded valve disc for safety actuation. An exterior cylinder, actuated pneumatically by gas (usually air or nitrogen) opens the valve mechanically in the relief mode by means of a lever connected to the main valve disc.

Relief valves and SRVs usually discharge into the suppression pool. Separate safety valves, however, usually discharge into the dry containment volume. For this reason, inadvertent opening of relief valves do not represent a significant cause of release of radioactivity to the environment (as noted in NUREG-0462). This report notes that these events "...have neither significantly affected the structural integrity or capability of the reactor vessel, the reactor vessel internals, or the pressure suppression containment system...." These conclusions are only of peripheral interest to this present report whicn concerns itself solely with the possible damaging effect of a stuck-open relief valve on the reactor core and the remainder of the plant.

2.2 Transients Resulting in Opening of Relief Valves (or SRVs in the Relief Mode)

GE has reported that various events could be expected to open SRVs. These events are listed in Table B-2, together with the expected frequency of the events throughout a plant's lifetime. Calculations were made utilizing the REDY and SAFE computer codes in combination to determine the transients that would cause SRVs to open. The number of occurrences was determined by using past experience and engineering judgment to provide a conservative value for the expected frequency.

The data in Table B-3, provided by the BWR licensees, are intended to incorporate all safety and relief valve actuations in the last three years of operation. These data are tabulated under individual plants and separately by type of relief valve (either electromatic or SRV) in each plant. We examined the data in Table B-3 in order to determine what initiating event resulted in each valve actuation and recorded the results of this comparison in Table B-4 for comparison with the anlytical results in Table B-2. We must note, however, that a definitive comparison between analysis and data cannot be made because we have not reviewed the analytical results to determine whether they are conservative. However, we do see that the analytical expectation for events causing SRV actuation is a multiple (approximately three to six times, ignoring single events) of those actually occurring. When we come to the prediction for inadvertent relief valve opening, the situation is reversed, for the number of actual openings is a multiple (approximately five times) of those predicted. It is assumed

TABLE B-2

FREQUENCY OF SRV OPENING EVENTS (BWR/4 AND BWR/5 PLANTS)

		Safety Relief Valves Lifted on Initial Pressure Peak				
Event	Design Frequency* (40 Years)		All to 2/3	2/3 to 1/3	1/3 to 0	Isolation Type Event
Turbine Trip (with Bypass)	51		x			No
Load Rejection (with Bypass)	29		x			No
Pressure Regulator Failure	26			x		Yes
Feedwater Controller Failure	19			x		Yes
Trip of Both Recirculation Pumps	10			x		Yes
Recirculation Controller Failure	10			x		Yes
Loss of Feedwater Flow	29				x	Yes
Loss of Auxiliary Power	10		x			Yes
Closure of All MSIVs	38		x			Yes
Loss of Condenser Vacuum	26		x			Yes
Inadvertent Relief Valve Opening	4				x	Yes
Turbine Trip (without Bypass)	1	x				Yes
Load Rejection (without Bypass)	1	x				Yes

TABLE B-3

SRV OPENINGS EXPERIENCED DURING LAST THREE YEARS OF BWR PLANT OPERATION

Type of Event[1]	No. of Failures[2]				No. of Events
	IO-FTC	FTC	FTO	IO	
I. Overall Tabulation					
Transient	15	9	6	6	57
Operator Error	0	3	0	1	22
I/C[3]	0	3	0	1	10
Test	1	1	11	0	98
Total	16	14	17	8	187
II. Events, Failures Differentiated by Valve Type					
A. Plants with Safety/Relief Valves					
Transient	14	9	6	6	51
Operator Error	0	3	0	0	19
I/C	0	1	0	0	9
Test	0	0	5	0	45
Total	14	13	11	6	124
B. Plant with Separate Electromatic Relief Valve					
Transient	1	0	0	0	6
Operator Error	0	0	0	1	2
I/C	0	0	0	1	1
Test	1	1	6	0	53
Total	2	1	6	2	61
C. Big Rock Point - Humbolt Bay[4]					
Transient	0	0	0	0	0
Operator Error	0	0	0	0	1(5)
I/C	0	0	0	0	0
Test	0	0	0	0	0
Total	0	0	0	0	1(5)

TABLE B-3 (Continued)

Individual Plant Data

Plant	Cause of Initiating Event			
	Transient	Operator	I/C(3)	Test
Duane Arnold(11)	2(0)	1(0)	---	---
Big Rock Point	---	1(0)	---	---
Browns Ferry 1(11)	4(0)	2 (FTC)	2(0)	6(0)
Browns Ferry 2(11)	4[3(IO-FTC)]	1(0)	---	4(0)
Browns Ferry 3(11)	3(IO-FTC,3FTC)	5(FTC)	3(FTC)	5(0)
Brunswick 1	7(5 FTC,IO)	---	---	---
Brunswick 2	4[3(IO-FTC)FTC]	--	---	---
Cooper(11)	3(0)	2(0)	---	---
Dresden 1	---	---	---	---
Dresden 2	---	---	---	3(FTC, FTO)
Dresden 3	(IO-FTC)	---	---	5(IO-FTC)
FitzPatrick	4[2(IO-FTC IO, FTC)]	5(0)	---	---
Hatch 1	5[3(IO-FTC 5 FTO)]	1(FTC)	---	1(2 FTO)
Hatch 2	---	---	---	2(2 FTO)
Humboldt Bay	---	---	---	---
Millstone 1	4[4 IO](7)	---	---	1(0)
Monticello	2(0)	---	---	12(0)
Nine Mile Point	---	---	---	4(2 FTO)(8)
Oyster Creek	2(0)	1(0)	1(10)	8(0)
Peach Bottom 2(11)	7[2(10-FTC)]	---	---	8(0)
Peach Bottom 3(11)	1(IO-FTC)	---	4(0)	5(0)
Pilgrim(11)	6(FTO, 3 FTC)	---	---	1(FTO)
Quad Cities 1	2(0)	1(IO)	---	15(2 FTO)
Quad Cities 2	1(0)	---	---	18 (FTO)
Vermont Yankee(11)	---	2(0)	---	---

TABLE B-3 (Continued)

Notes for Table

(1) Attributed initiating cause

(2) Failure modes shown are:

IO - Inadvertent Opening
FTC - Failure to Close
FTC - Failure to Open

(3) Failure of instrumentation or control

(4) Plants without relief valves

(5) Steam drum safety valve

(6) Valves were modified (three stage to two stage) after these events

(7) While testing for ground (11-29-77), positive conductor of solenoid cable faulted to ground, bulb in positive leg of ground detector circuit had bridged filament.

(8) Same valve (No. 122) failed twice - on test, retest. Operated on second retest.

(9) Numbers outside of parentheses show number of events attributed to this particular initiating cause; numbers inside show number and type of failures.

(10) Dresden Units 1, 2, 3; Nine Mile Point; Oyster Creek; Quad Cities 1, 2 have electromatic relief valves. Big Rock Point and Humboldt Bay do not have relief valves. All the remaining plants use SRVs. Note that Dresden 1, 2, 3; Quad Cities 1, 2 each have one SRV.

(11) Plants with separate safety valves in addition to SRVs. All plants with the exception of Cooper have two safety valves; Cooper has three.

(12) Valves set to operate automatically only in safety mode or ADS mode. Valves may be operated manually as needed.

TABLE B-4

OPERATIONAL EVENT FREQUENCY

Event	Frequency in Plants with Electromatic Relief Valves	Frequency in Plants with SRVs
Turbine Trip with Bypass	0	11
Load Rejection with Bypass	0	5
Feedwater Controller Failure	0	7
Loss of Feedwater	0	7
Loss of Auxiliary Power	1	1
MSIV Closure	0	1
Loss of Condenser Vacuum	0	2
Inadvertent Relief Valve Opening	1	19

that a prediction of relief valve opening is based upon past experience or upon expectation of future experience with valves in BWR/4 and BWR/5 plants (for which the predictions were made). This comparison does present a clear view of SRV maloperation because we find, of the 53 events in Table B-4 causing SRV actuation, 19 cases are actual inadvertent valve actuations for a rate of approximately 36 percent of the total or a failure rate of 19 per 46 reactor years or 0.4 failures per reactor year. Note, however, that data for plants with separate electromatic relief valves show only one inadvertent opening in 21 reactor years, a rate of failure of 0.05 per reactor year.

The data in Table B-4 have to be viewed with some qualification. In many cases, the data provided were not detailed sufficiently so that events could be placed in the categories shown in Table B-4 with absolute assurance that such placement was correct. Further, detailed reports from the plant or further examination of instrument recorder charts at the plant is necessary to establish, definitively, the transient category which applies to each and every event.

2.3 Performance

In order to bring SRV actuations and failures up to date, the Owners Group was asked to provide information regarding relief valve operation and failures in the last three years of operation (Table B-3). From the overall tabulation, we find a total of 55 valve failures in 187 events in which a relief valve was challenged or actuated. Note that failures shown as 10-FTC indicate that one particular valve both opened inadvertently (10) and failed to close (FTC) - the combination may indicate a defective pilot valve (and is tabulated here as a single failure). If we separate the events by type of valve, we find 11 failures in 62 events for plants with electromatic relief valves while those with SRVs show a total of 44 failures in 124 events. If we consider only those cases in which a relief valve failed to close (a potential source of small-break LOCA), the data show three failures in 62 events (0.05 failures per event) for electromatic relief valves versus 27 failures in 124 events (0.22 failures per event) for SRVs. The number of failures of SRVs in this mode (failure to close) seems inordinately high.

Based on reactor years of operation (approximately 46) for the 16 plants employing SRVs, we determine a failure rate (FTC) of 27 failures/ 46 reactor years or 0.59 failures per reactor year. This contrasts with the electromatic relief valve failure rate of three failures/19 reactor years or about 0.16 per reactor year (for six plants). Plants without normal relief function (Big Rock Point, Dresden, and Humboldt Bay) reported only one event with no valve failure. These plants will be largely ignored in the discussion to follow since they do not contribute materially to the problem of relief valve failures as noted above.

Overall, there are a total of 124 events (approximately 2.5 per reactor year) for plants employing SRVs and 62 events (approximately three per reactor year) for plants with electromatic relief valves. These include transients resulting from operator error, malfunctioning instruments and/or controls, and testing. Note that about 85 percent of the total number of events for plants with electomatic valves are test events with test events constituting 37 percent of the events for plants with SRVs. The number of events in plants with SRVs does not seem different, including or excluding test events.

For transient events, there are 23 failures (FTC) in 51 events for SRVs; one failure in six events for electromatic valves.

WASH-1400 determined the probability (Table III 6-9, Appendix III) of a small pipe break initiating a LOCA to be from 10^{-2} to 10^{-4}, per reactor year with a median value of 10^{-3}*; none of the reported events resulted in damage to the core for a failure rate of zero (no failures) in a total of 64 reactor years. Further examination of these occurrences is required in order to assure that the hypothesis of zero failures is, indeed, true. These occurrences should also be examined with a view toward determining whether any small change in response could have affected plant safety. The failure rates seem to be consistent with the expectation of an anticipated operational occurrence. Indeed, Section 15.6.1 of the Standard Review Plan considers the inadvertent opening of a safety or relief valve to fall into the category of anticipated operational occurrences, requiring that "...99.9 percent of the fuel rods would not be expected to experience boiling transition...." Furthermore, Section 15.6.1 states that "An incident of moderate frequency, in combination with any single active component failure or single operator error should not cause loss of function of any barrier other than fuel cladding. A limited number of fuel rod cladding performations is acceptable." The totality of features in the events tabulated in Table B-3, 55 in 64 reactor years (0.86 failures per reactor year), seem to fall into the first category since no fuel failures have been reported in these events. Further examination is necessary to verify this tacit assumption.

This tacit assumption is reinforced by the discussion in WASH-1400 regarding inadvertent release of coolant as a result of a failure of a BWR relief valve to close after being opened. WASH-1400 states that:

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*Note that EPRI (EPRI NP-1130), in its evaluation of the Lewis and EPRI reviews of the Reactor Safety Study generalizes regarding the WASH-1400 results:

> "This report demonstrates that the WASH-1400 numerical results cannot be significantly optimistic and are most likely quite pessimistic. The maximum optimism is a factor of less than four. The most likely result is (1) the WASH-1400 mean is pessimistic (high) by a factor of 12 and (2) the WASH-1400 error bars (5,95) are too small by a factor of 13."

> "...It can also be seen from operating experience that the coolant loss in general, has been of small magnitude which has not led to automatic actuation of the emergency core cooling systems because plant makeup systems normally in use (such as feedwater/condensate pumps and the control rod drive pumps) have provided for the resultant losses in coolant inventory through the failed-open valves. Thus these indicents would not be classed as LOCAs. Nonetheless, the frequency of these accidents has been of some concern to safety authorities."

We do not completely agree with this statement without qualification; we feel that this only applies in case of SRV failure to close following an inadvertent opening or a transient which causes the valve to open, without subsequent isolation of the primary system. Valve failures (FTC) as a result of transients causing isolation would require some auxiliary water makeup system, usually ECCS, because isolation results in loss of feedwater. Nonetheless, this reinforces the idea that BWRs respond to a situation of an open SRV with no apparent difficulty.

The foregoing discussion is not intended to imply that the single failure philosophy will continue to be applied. The TMI-2 Lessons Learned Task Force has recommended that alternates to the concept of single failure be examined as a means to enhance plant safety. However, the staff considers, as an interim judgment, that the capability of BWRs to withstand transients with a single failure (SRV or relief valve failure to close) without violation of the criteria for transients without single failure, i.e., conformance to minimum critical power ratio (MCPR) criteria, to be sufficient, in the interim, to prevent damage as a result of a stuck-open relief valve or SRV. This is contingent upon two criteria: (1) that we find that plants did not violate MCPR criteria in transients which result in relief valves remaining open, and (2) that SRV operation be modified in operating plants to reduce the number of failures to close and the number of inadvertent openings. Obviously, the latter criteria will have a material effect on the potential for plant damage resulting from a stuck-open relief valve.

In view of the foregoing, there does not appear to be a need for any immediate changes in BWR plants to reduce the probability of a small-break LOCA resulting from an open electromatic valve or SRV. However, because of what appears to be an inordinately high rate of failure of SRVs, both in inadvertently opening and failure to close, we feel that SRVs should be improved. With that in mind, we will consider alternatives to reduce potential valve failures. These alternatives are discussed below.

2.4 Valve Discharge Capability

Electromatic relief valves and SRVs are located on steam lines and open to discharge steam to the suppression pool when system pressure rises to the set value.

Steam relieving capacities of the electomatic valves were determined based upon analyses and geometric similarity of these valves to the Dresser "Electromatic" type 1538 XV valve which had been qualified under the rules of Section I of the ASME Code. Relieving capacity of safety valves, however, was established in accordance with the rules of Section III of the ASME Code since the relieving capacity of these valves is considered and given credit for in the vessel overpressure protection analyses; no allowance is given for relieving capacity of relief valves or for the relief mode of SRVs.

In normal transients the fluid passing through relief and SRVs is steam. Some plants utilize the automatic depressurization system (a safety function of safety valves and safety/relief valves) as an alternate method for plant cooldown to the point at which the residual heat removal system takes over. This function may require relief of water or steam/water combinations. If relieving capability in this mode cannot be completely justified, valves will be tested in order to assure their capability under these abnormal conditions.

2.5 Alternatives to Increase SRV Reliability

2.5.1 Design Change

SRVs appear to be delinquent both in opening inadvertently and failing to close. GE has recommended modifications which include replacement of present three-stage Target Rock valves with two-stage valves (Figure B-3). The effect of this change will be evaluated by the staff.

2.5.2 Setpoint Modification

An alternate procedure that has been suggested by GE would be to change the pressure setpoint so that the simmer margin (the margin between operating pressure and relief valve setpoint) is increased. The effect of this change has not yet been evaluated.

2.5.3 Valve Maintenance

GE has also recommended increased valve maintenance with more stringent leakage criteria for early detection and removal to reduce SRV failures.

2.5.4 Elimination of Relief Function

Elimination of the relief function would, of course, also eliminate SRV actuation at relief valve setpoints but would not eliminate safety valve actuation at higher pressures. This may reduce the number of actuations but will ultimately cause the SRVs to open at higher pressures increasing the possibility of a SRV remaining open in the safety mode.

Figure B-3

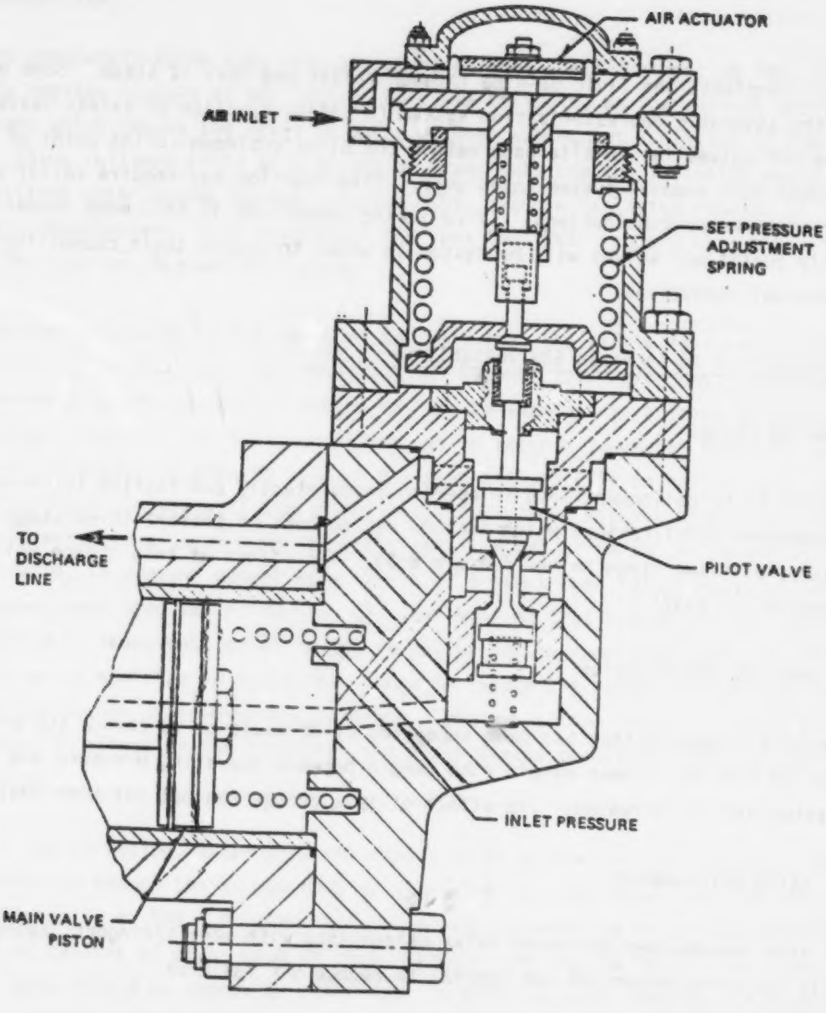

AIR ACTUATOR
AIR INLET
SET PRESSURE ADJUSTMENT SPRING
TO DISCHARGE LINE
PILOT VALVE
INLET PRESSURE
MAIN VALVE PISTON

Figure B-3 Two-Stage Pilot-Operated Pressure Relief Valve

No assessment has been made as to whether increased safety is derived from this change.

2.5.5 Reduction in Number of Events

Plants with SRVs do not appear to have a markedly increased rate of events causing relief valve actuation. Further examination is required to ascertain whether such rates are excessively high.

2.5.6 Lessons Learned Task Force Recommendations

The Lessons Learned Task Force recommended that BWRs and PWRs be provided with either a direct indication of safety relief valve position or with a reliable flow indication device to indicate open valve status. At present, most BWRs do not have direct relief valve position indicators.

The Lessons Learned Task Force also recommended that both safety and relief valves in BWRs and PWRs be tested for functional performance capability. Some question arises because of the failure of the power-operated relief valves to close at TMI-2 and at the Beznau plant as to whether these valves have sufficient relief capability and can sustain the loads imposed during accidents in which two-phase slug flow or single-phase steam or water flow is relieved. GE has reported that their calculations show in their transient and accident analyses that the water or two-phase fluid level in the reactor never rises to the level of the steam lines, thereby obviating the need for two-phase slug flow or single-phase water flow through the relief or safety valves. This analysis and conclusion will be examined by the staff in order to determine whether safety and/or relief valve flow testing is required to assure valve performance in accordance with that determined by calculations.

2.6 Conclusions and Recommendations

At this time, we see no need to make any modifications in BWRs because of the capability of BWRs to recover from SRV or relief valve failure to close without a resultant LOCA.

We have seen that relief valves, in failing to close, have not resulted in damage to BWR reactor cores or plants. While the failures to close appear to be inordinately high, the number of resultant small-break LOCAs is not. However, we are not able to determine from the licensees' data the expectation or probability of a small-break LOCA. We do see the need for a reduction in the number of failures of SRVs to close and open inadvertently. Towards this end, we will evaluate the recommendations and data presented by the GE and other recommendations to resolve this problem.

We also recommend examination of past events in order to provide assurance that no core damage occurred, and to ascertain whether any slight change in response could have affected plant safety with a view toward improving procedures and plant actions to perfect plant safety.

2.7 Final Notes

Dresden 2-3 and Quad Cities 1-2 utilize one SRV in each plant to operate at a lower pressure than the four electromatic relief valves. Therefore, the failure data may include failures of both electromatic relief valves and SRVs. This does not invalidate the comparisons, however, it reinforces them. In all cases, we have concluded that electromatic valves are superior to SRVs. If they were inferior, the inclusion of SRV failure data with eletromatic data would have aggravated the inferiority of the electromatic valves. There is a slight posisibility that the SRVs, by opening early, protected the electromatic valves and this should be investigated. This is unlikely, however, because the SRV failure rate should then have increased and it does not appear to have increased. This, also, requires further examination, e.g., to ascertain whether the SRVs in older plants are superior in some way to those in newer plants.

In comparison with relief valve failures in PWR plants, BWR plant SRVs seem to be worse by a factor of three to five than those used in B&W plants and by a factor of 10 to 100 than those in Westinghouse plants. Part of these failures may be ascribed to valve differences but part of the differences are in the nature of the differences in relief required by PWR and BWR plants. Most PWR plants have two relief valves (Cooper has three), and, therefore, only one or two open in events requiring pressure relief. BWR plants have as many as 11 SRVs in most of the plants considered herein with three or four opening for events requiring minimum pressure relief and all 11 for maximum relief. An SRV failure rate three to five times greater than relief valves in PWR plants would be expected, even if the valves in BWR and PWR plants had identical failure rates. On cursory examination, SRV failure rate does appear to be even greater than can be accounted for by the differences in the number of valves.

APPENDIX C

OPERATOR TRAINING AND OPERATING PROCEDURES CONSIDERATIONS

1. TRAINING

1.1 Findings (Previously stated in NUREG-0560)

Operator training has evolved over the last ten to fifteen years from concentrated on-the-job training programs, with little time allotted to formal training, to the current more formal NRC-approved programs. In addition, the expanded use of simulators has contributed significantly to the quality of operator training.

The NRC staff's Operator Licensing Branch (OLB) has used simulators, where practical, in its examination of applicants for operator licenses for approximately five years. The OLB finds that such examinations are much more demanding than normal "walk-thru" type examinations. The simulator examinations are more demanding on both the applicant and the examiner in that they require a more detailed understanding of the nuclear system. As a result, a better evaluation of an individual's operating ability can be made by using a simulator. However, the extent of the improvement in evaluation potential in each case is highly dependent on the degree of similarity between the simulator and the plant that the individual will actually operate.

In the past, training programs have given insufficient emphasis to non-standard passive conditions such as misaligned systems, undetected failures of engineered safety feature equipment, and multiple failures. Irrespective of the merits of the single failure criterion as a design basis, it should not be considered as a limiting basis for training purposes.

It is generally acknowledged by the NRC staff and the operators themselves that simulator operation is a valuable part of operator training. This consensus is reinforced in EPRI Report NP-309, which states in part that, "Operators regard simulators as the best vehicle for obtaining operational training . . . it helps you to see casualty modes." It is also apparent from the TMI-2 accident that transient recognition by the operator and the operator's response based upon his understanding of the plant status is essential to reactor safety. We believe that a primary part of operator training in event recognition and response should be actual "hands-on" operation in response to various plant transients and accidents. This sort of experience can be gained to some degree through actual plant operation and walk-thrus, but must include event simulation and actual operator response and observation to be most meaningful.

1.2 Recommendations

(1) All licensed operators should be required to participate in a simulator training program to observe such events as stuck-open relief or safety valves. Training on

protecting the core should be emphasized at all plants. This includes the means to recognize that an adequate heat sink, primary system inventory, and an intact primary system exist. Simulator training programs should be reviewed to assure that they include the operator errors and equipment failures similar to those that contributed to the TMI-2 accident. An evaluation of the simulator control board design and simulated response as compared to the operator's actual plant response and actual control board design should be made on a case-by-case basis. The differences which may exist should be addressed as part of the operator's training so that negative training feedback will not result.

(2) As stated in Appendix F to this report, plant simulators should offer, as a minimum, the following small-break LOCA scenarios:

(a) Continuous depressurization,
(b) Pressure stabilized above the low pressure ECC system initiation setpoints,
(c) Repressurization, and
(d) Repressurization resulting in a stuck-open relief valve.

Each of these cases should be simulated with breaks occurring at different locations in the system. Breaks in the steam line, recirculation lines, feedwater lines, and the control rod coolant lines should be modeled and incorporated for operator training. In addition to the usual failures in ECC and feedwater system, complete loss of high pressure injection system should also be simulated in conjunction with the above events.

2. OPERATING PROCEDURES

2.1 Findings

Operating and emergency procedures are developed in accordance with Regulatory Guide 1.33, Appendix A, "Quality Assurance Program Requirements (Operation)" and Sections 5.3.2 and 5.3.9 of ANSI 18.7/ANS 3.2, "Administrative Controls and Quality Assurance of Operation of Nuclear Power Plants."

Each normal operating procedure involves the use of checklists and is based on a controlled evaluation giving final conditions as goals to achieve. On the other hand, abnormal and emergency procedures are completely different in that the operator is confronted with automatic responses for which he may have to take manual actions. Therefore, when writing the abnormal and emergency procedures, consideration should be given to the real time that it takes for systems to respond and for the operator to perform manual functions. (The preceding material was previously stated in NUREG-0560).

Before the TMI-2 accident, little attention was paid to operational procedures, especially to emergency procedures and their relationship to the supporting safety analyses. Unambiguous diagnostics and proper precautions and prohibitions were not always considered in the development of procedures.

The NSSS vendor usually does not check a customer's procedures to determine whether the vendor's operational guidelines have been properly incorporated into the plant procedures.

Emergency operating procedures currently in use at operating plants have evolved on an "event-specific" basis. Symptom-based emergency procedures, which are categorized according to general plant symptoms and include the essential features of several separate existing associated procedures, could make use of the fact that the initial operator responses to the associated events are similar.

During our October 25, 1979, meeting with the Owners Group, the Owners Group advised us that following our approval of the guidelines associated with small-break LOCAs, inadequate core cooling, and transients and accidents, it plans to embark on a new emergency operating procedure philosophy. This philosophy would involve restructuring and reformatting the emergency operating procedures presently in use at operating BWR plants on a "symptom" basis, as opposed to the more "event-specific" basis on which these procedures are evolved.

The symptom-based emergency procedures would be categorized according to general plant symptoms, such as loss-of-coolant inventory, as opposed to the several separate existing associated procedures, such as LOCA inside containment, LOCA outside containment, and loss of normal feedwater. The loss-of- coolant inventory procedure would include the essential features of those existing procedures associated with LOCA inside containment, LOCA outside containment, and loss of normal feedwater, and would make use of the fact that the initial operator responses for the latter procedures are similar. The principal advantages of the symptom-based emergency procedures over the event- specific procedures are: (1) the procedures as a whole would be simplified significantly and would, therefore, not require the operator to make a detailed diagnosis of the plant conditions prior to consulting an emergency procedures, (2) the total number of emergency procedures with which the operator would have to contend during an emergency would be reduced significantly, and (3) such an exercise would necessitate that the licensees look again at their emergency procedures in a more integrated manner. These advantages would contribute significantly to the ability of the operator to maintain the plant in a safe condition in the event of an emergency.

2.2 Recommendations

(1) The NRC should become more involved in the review of procedures, including their correlation with the assumptions made in the supporting safety analyses. The procedures should include recognition of the event, precautions, actions, and prohibited actions.

(2) Independent of the NRC review of procedures, the NSSS vendor should confirm that the vendor's operational guidelines have been properly incorporated into the customer-licensee's plant operating procedures. Any exceptions which the customer-licensee may have taken to the vendor's guidelines should be documented with appropriate justification. Copies of the correspondence regarding such exceptions should be transmitted to the NRC for information.

(3) Licensees whose emergency procedures have been developed on an event- specific basis should restructure and reformat these procedures on a symptom basis.

3. HUMAN FACTORS

3.1 Findings

The operator must understand his responsibilities during abnormal and emergency conditions. The design basis for the plant has provided that, in the event of emergencies, suitable actions will be automatically initiated by the safety systems. The operator's initial responsibility is to monitor the parameters of interest and verify that appropriate safety systems have been actuated. If the appropriate actuations have not occurred, the operator must intercede and perform whatever action is necessary to implement them.

The operator has been trained to believe his instrumentation. However, he must be trained not to rely on a single instrument since any single indication may be erroneous and misleading under certain conditions. The reason for this precaution was clearly illustrated at TMI-2, where operator attention was focused on pressurizer level indication. In virtually all situations, other instrumentation can be used to corroborate or refute the validity of a given instrument.

3.2 Recommendations

The operator should monitor the control board and evaluate all parameters of concern by the appropriate checking of other instrumentation. He must perform this cross-check to verify instrument display. If he has additional manual actions to perform, he may reduce his observation on other systems' parameters that may lead to "tunnel vision". This recommendation should be implemented in operator training programs.

4. OPERATOR ACTIONS DURING RECOVERY FROM LOSS OF FEEDWATER TRANSIENTS

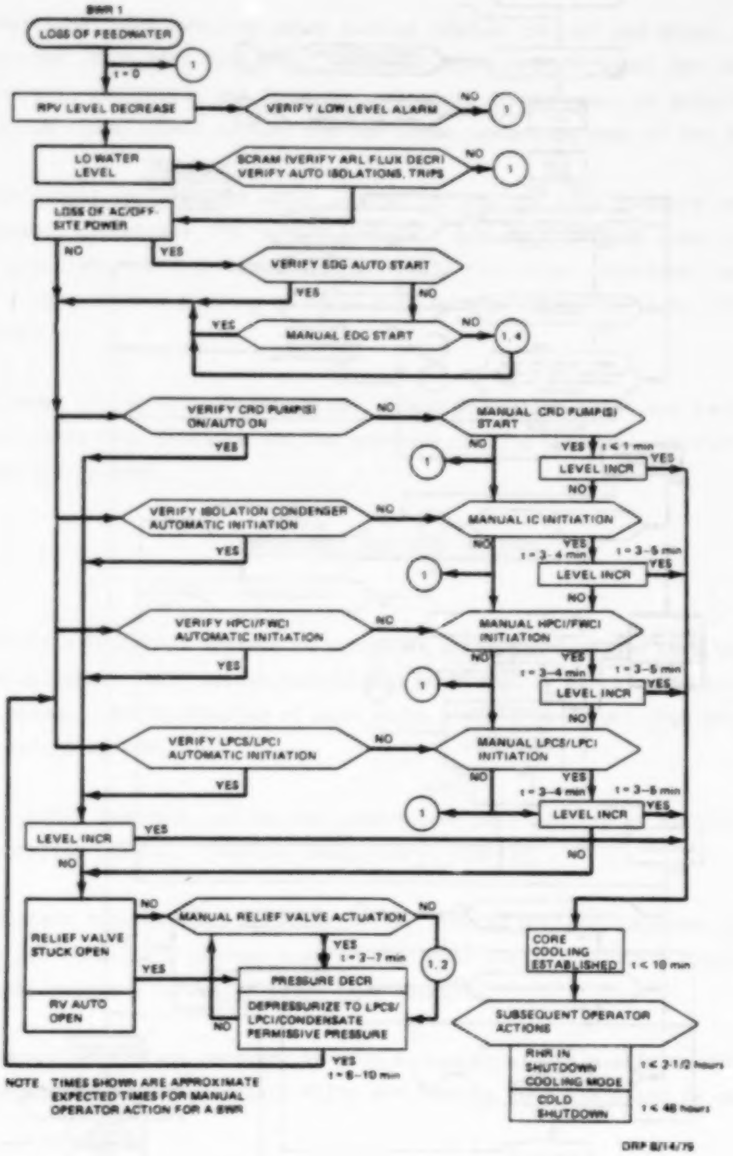
4.1 Background

The Owners Group was requested to provide an operator scenario for response to a loss of feedwater transient. This scenario was to include operator response with combinations of degraded conditions including loss of offsite power, stuck-open safety/relief valve, failure of the HPCI or HPCS system, failures of the RCIC system or isolation condenser, ADS failure, and failures of the LPCI and LPCS systems. These operator scenarios were to constitute success paths; as such they were to serve as guidance in developing guidelines or procedures for coping with a loss of feedwater with degraded conditions.

The Owners Group response, provided in NEDO-24708, is shown in Figure C-1 for the BWR/1 plants and in Figure C-2 for the BWR/2 through BWR/5 plants. These operator scenarios rely upon whatever systems are available, in order of preference, whether they are safety-grade or non-safety systems.

4.2 Conclusions

We have concluded that because multiple system failures are included in the operator scenarios, they go well beyond the guidance previously provided to operators. Further, they constitute realistic operator actions for responding to the event and depict actions necessary to assure adequate core cooling. These operator scenarios should be used in developing guidelines for loss of feedwater events and should prove helpful in developing guidelines or procedures for loss of inventory events in general.


BWR 1
LOSS OF FEEDWATER
t = 0
1
RPV LEVEL DECREASE
VERIFY LOW LEVEL ALARM
NO
1
LO WATER LEVEL
SCRAM (VERIFY ARL FLUX DECR) VERIFY AUTO ISOLATIONS, TRIPS
NO
1
LOSS OF AC/OFF-SITE POWER
NO
YES
VERIFY EDG AUTO START
YES
NO
YES
MANUAL EDG START
NO
1, 4
VERIFY CRD PUMP(S) ON/AUTO ON
NO
MANUAL CRD PUMP(S) START
YES
NO
YES
t ≤ 1 min
1
LEVEL INCR
YES
NO
VERIFY ISOLATION CONDENSER AUTOMATIC INITIATION
NO
MANUAL IC INITIATION
YES
NO
YES
t = 3-4 min
t = 3-5 min
1
LEVEL INCR
YES
NO
VERIFY HPCI/FWCI AUTOMATIC INITIATION
NO
MANUAL HPCI/FWCI INITIATION
YES
NO
YES
t = 3-4 min
t = 3-5 min
1
LEVEL INCR
YES
NO
VERIFY LPCS/LPCI AUTOMATIC INITIATION
NO
MANUAL LPCS/LPCI INITIATION
YES
NO
YES
t = 3-4 min
t = 3-5 min
1
LEVEL INCR
YES
LEVEL INCR
YES
NO
NO
RELIEF VALVE STUCK OPEN
NO
MANUAL RELIEF VALVE ACTUATION
NO
YES
t = 2-7 min
1, 2
YES
PRESSURE DECR
RV AUTO OPEN
DEPRESSURIZE TO LPCS/LPCI/CONDENSATE PERMISSIVE PRESSURE
NO
YES
t = 6-10 min
CORE COOLING ESTABLISHED
t ≤ 10 min
SUBSEQUENT OPERATOR ACTIONS
RHR IN SHUTDOWN COOLING MODE
t ≤ 2-1/2 hours
COLD SHUTDOWN
t ≤ 48 hours

NOTE TIMES SHOWN ARE APPROXIMATE EXPECTED TIMES FOR MANUAL OPERATOR ACTION FOR A BWR

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Figure C-1 Operator Action Scenario (BWR/1 Plants)

Figure C-2

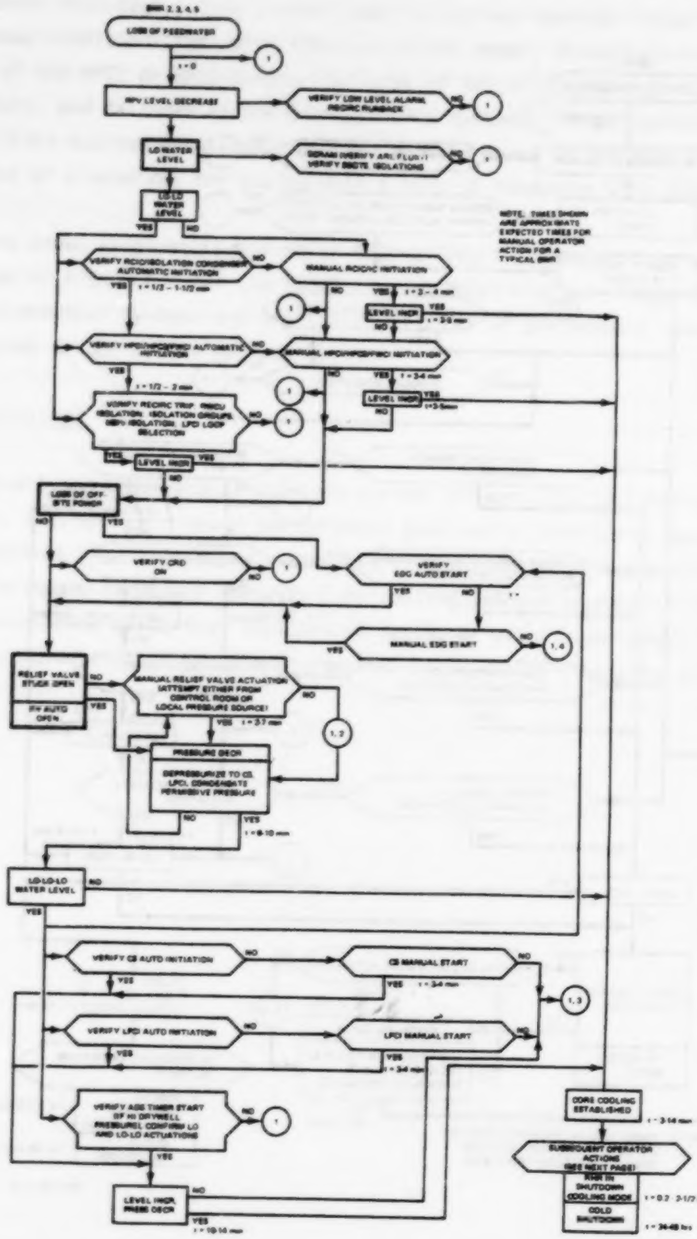
BWR 2, 3, 4, 5
LOSS OF FEEDWATER
t = 0
1
RPV LEVEL DECREASE
VERIFY LOW LEVEL ALARM RECIRC RUNBACK
NO
1
LO WATER LEVEL
SCRAM (VERIFY ARI, FLUX) VERIFY MSIV ISOLATIONS
NO
1
LO-LO WATER LEVEL
YES
NO
NOTE: TIMES SHOWN ARE APPROXIMATE EXPECTED TIMES FOR MANUAL OPERATOR ACTION FOR A TYPICAL BWR
VERIFY RCIC/ISOLATION CONDENSER AUTOMATIC INITIATION
NO
MANUAL RCIC/IC INITIATION
YES
t = 1/2 - 1-1/2 min
NO
YES
t = 2 - 4 min
1
LEVEL INCR
YES
t = 3-5 min
NO
VERIFY HPCI/HPCS/FWCI AUTOMATIC INITIATION
NO
MANUAL HPCI/HPCS/FWCI INITIATION
YES
t = 1/2 - 2 min
NO
YES
t = 2-4 min
1
LEVEL INCR
YES
t = 3-5 min
NO
VERIFY RECIRC TRIP, RWCU ISOLATION, ISOLATION GROUPS, MSIV ISOLATION, LPCI LOOP SELECTION
NO
1
YES
LEVEL INCR
YES
NO
LOSS OF OFF-SITE POWER
NO
YES
VERIFY CRD ON
NO
1
VERIFY EDG AUTO START
YES
NO
t =
MANUAL EDG START
YES
NO
1, 4
RELIEF VALVE STUCK OPEN
RV AUTO OPEN
NO
YES
MANUAL RELIEF VALVE ACTUATION (ATTEMPT EITHER FROM CONTROL ROOM OR LOCAL PRESSURE SOURCE)
NO
YES
t = 3-7 min
1, 2
PRESSURE DECR
DEPRESSURIZE TO CS, LPCI, CONDENSATE PERMISSIVE PRESSURE
NO
YES
t = 6-10 min
LO-LO-LO WATER LEVEL
NO
YES
VERIFY CS AUTO INITIATION
NO
CS MANUAL START
NO
YES
YES
t = 3-4 min
1, 3
VERIFY LPCI AUTO INITIATION
NO
LPCI MANUAL START
NO
YES
YES
t = 3-4 min
VERIFY ADS TIMER START (OF HI DRYWELL PRESSURE) CONFIRM LO AND LO-LO ACTUATIONS
NO
1
YES
LEVEL INCR PRESS DECR
NO
YES
t = 10-14 min
CORE COOLING ESTABLISHED
t = 3-14 min
SUBSEQUENT OPERATOR ACTIONS (SEE NEXT PAGE)
RHR IN SHUTDOWN COOLING MODE
t = 0.2 - 2-1/2 hrs
COLD SHUTDOWN
t = 24-48 hrs

Figure C-2 Operator Action Scenario (BWR/2 Through BWR/5 Plants)

NOTES ON FIGURE C-2

(1) Take prompt operator (or maintenance) action as severity of failure or transient warrants. Priority of safety actuations must be considered in restoring failed equipment. Do not underman control room. Utilize approved plant operating, maintenance, and emergency procedures.

(2) Additional high pressure water sources include control rod drive, standby liquid control (from test tank only), HPCI and RCIC (install spool for steam from auxiliary boiler), condensate and feedwater (electric driven pumps or deisolate MSIVs with vacuum established) systems and the steam condensing mode of the RHR/RCIC systems.

(3) Additional low pressure water sources include the high pressure sources (see (2) above), condensate, ECC system keep-full systems (charging pumps or flushing connections fed from condensate storage), fire water injection, continued blowdown through shutdown cooling to torus with service water tie-in to LPCI (last resort only).

(4) Attempt to restore off-site power, transfer station loads and manually start available high pressure and low pressure cooling systems. Reestablish plant service systems.

Subsequent Operator Actions

(A) Maintain HPCI/HPCS systems in automatic until low pressure core cooling is established. RCIC system control may be placed in manual when initial coverage is achieved. Avoid flooding of main steam lines with either high pressure or low pressure systems.

(B) Establish shutdown cooling and suppression pool cooling as soon as LPCI system operation permits. Monitor temperatures closely.

(C) Maintain suppression pool water level. Verify HPCI/HPCS system suction transfer on low condensate storage tank or high pool level. Maintain condensate storage tank inventory (transfer water from hotwell).

(D) Proceed with plant recovery as soon as reactor is in a safe condition. Restore condenser vacuum, deisolate MSIVs and restore condensate and feedwater.

Cautions

(A) Automatic ECC system controls should not be placed in manual/override unless (1) misoperation in automatic/standby is confirmed by at least two independent indications of system degradation or (2) unless core cooling is established as verified by at least two independent parameters.

(B) Reset trips and isolations as soon as possible after cause of event is determined. Return manual controls to automatic/standby promptly (as required by Technical Specifications and plant conditions).

(C) Observe all Technical Specification limits.

APPENDIX D

LICENSING BASIS AND REGULATIONS

1. LICENSING OVERVIEW

The NRC makes the determination before a license is granted that there is reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. A body of requirements has been provided for the design and operation of nuclear power plants to assure safety. The principal elements of these requirements are contained in the Code of Federal Regulations, Title 10 Part 50, especially in Appendix A, General Design Criteria (GDC). License applicants are required to include the results of a safety analysis covering the significant design features of the reactor plant for review by the NRC prior to construction and operation. These analyses are provided in the preliminary and final safety analysis reports (PSAR and FSAR respectively). In order to organize the PSAR or FSAR for each plant into a document treating all requirements, a standard format and content guide (NUREG-75/094) was developed to specify information requirements for the applicants' safety analysis reports. To assure a consistent review of each plant's safety analysis report by NRC, a Standard Review Plan (NUREG-75/087) was developed. In addition, regulatory guides have been developed to more specifically provide interpretations of the GDC acceptable to the NRC staff for the design of nuclear power plants.

A defense-in-depth approach to safety is embodied in the regulations. This approach leads to multiple barriers against the release of radioactive material. Similarly, reactor and plant systems important to safety are constructed and tested to criteria consistent with their importance to safety; namely, the fuel cladding, the primary system pressure boundary, and the containment building. Then engineered safety systems are provided to mitigate the consequences of various postulated events. Safety systems are required to be designed to accommodate single active failures in these systems in addition to the effects of the initiating event without loss of their safety function. Some passive failures also must be considered. Due to the evolving nature of NRC's requirements, not all safety systems in older plants meet the single failure criterion as it is now applied on new applications.

Preoperational and startup tests are performed on each plant to assure that the plant and its safety systems are operational and can perform as designed. Technical Specifications identifying and limiting conditions for plant operation are appended to the operating license. Maintenance, inspection, and operational considerations are subjects of interaction between the NRC and the licensee throughout the life of the plant.

The operators of nuclear power plants are subject to licensing requirements specified by the NRC. The operator licensing process includes initial training in nuclear technology, understanding of generic designs, and simulator training. Subsequently, final training takes place at the home facility where actual experience is obtained, including the use of procedures for normal, abnormal, and emergency operations. The culmination of this training program is an NRC reactor operator license examination which operators must pass in order to be licensed to operate the plant.

In this appendix, certain aspects of the NRC licensing process are evaluated in light of the TMI-2 accident of March 28, 1979. Specifically, the following is addressed:

(1) Loss of feedwater events for boiling water reactors including a consideration of initiating events that lead to pressurization of the primary system causing the relief valves to actuate,

(2) Status of models used in safety analysis, especially with regard to transients and small-break LOCAs, and

(3) Standard Review Plans (SRPs) and their applicability to transients and small-break LOCAs.

2. FINAL SAFETY ANALYSIS REPORTS FOR OPERATING BWRS

2.1 Loss of Normal Feedwater

A loss of feedwater flow could occur from pump failures, feedwater controller failures, operator errors, or a high vessel water level (Level 8) trip signal. Loss of feedwater flow results in a reduction of vessel inventory which causes the vessel water level to drop. The first automatic corrective action is the low-level (Level 3) scram trip actuation. The Level 3 scram trip function meets the single failure criterion.

For BWR/2 through BWR/5 plants, MSIV closure would occur when the water level dropped to Level 2. Vessel inventory control systems such as the HPCI and RCIC system would also receive initiation signals at Level 2. After closure of the MSIVs, the safety/relief valves operate to remove decay heat and limit vessel pressure.

Calculations are typically performed for the first 50 seconds of the transient. This is long enough to show cycling of the safety/relief valves but not long enough to include HPCI or RCIC system injection nor long enough to demonstrate stable conditions.

Transient analyses must be carried far enough out in time to demonstrate stable conditions. This means that loss of feedwater flow analyses, among others, must include HPCI system or HPCS and RCIC system flow and must show the reactor conditions of level, flow, and pressure are either stable or cycling between the setpoint limits of the injection systems.

2.2 Loss of a Feedwater and HPCI (HPCS) and RCIC System

As discussed above, the loss of feedwater flow analyses typically presented in safety analysis reports are not carried far enough out in time to distinguish between results with or without high pressure injection systems, e.g., HPCI or RCIC systems. The extent of the analyses presented is typical of either transient but is not carried to a stable set of conditions. All new analyses should include the effects of a single failure in a high pressure system and should be carried to a set of stable conditions. Results of analyses discussed in NEDO-24708 are presented in Appendix F to this report.

3. STATUS OF MODELS USED IN BWR SAFETY ANALYSES

The computer codes used to evaluate the consequences of abnormal operational occurrences in BWR safety analyses are ODYN[1] and REDY[2]. The staff has completed review of all available information on the ODYN code and concluded that it provides acceptable best-estimate calculation predictions of the core response to pressurization transients. However, based on the available information, the staff has not approved all aspects of the ODYN licensing basis as described in Reference 1. The staff has come to an interim position and plans to publish a safety evaluation report in March 1980.

Reference 1, Volume 3, Tables 2-1 and 2-2, indicates the type of transients to be analyzed using the ODYN and REDY codes. The REDY code is under review for those transients listed in the above tables. Oak Ridge National Laboratory is conducting the review through a technical assistance contract under guidance of the staff. Completion of a draft safety evaluation report is scheduled for September 30, 1980.

4. STANDARD REVIEW PLAN

The Standard Review Plan requirements for the loss of feedwater and other anticipated transients have been reviewed to determine how differences in the present requirements would have led to improve the NRC's capability to predict or correct what occurred at TMI-2.

Under the "Areas of Review" and the "Review Procedures" subsections of Standard Review Plan Section 15.2.7, it is stated that "transients are reviewed to the point where a stabilized condition is achieved."

As noted during the discussion of the analyses presented in FSARs, the staff has accepted analyses wherein the critical parameters had not entered a stable region but were terminated at the time of high pressure injection. This should be changed.

Section 15.1 of Standard Review Plan states that "An incident of moderate frequency in combination with any single active component failure, or single operation error, should not result in a loss of function of any barrier other than fuel cladding. A limited number of fuel rod cladding perforations is acceptable."

The staff has been aware that anticipated operational occurrences plus a single failure are not rigorously pursued, especially with regard to a stuck- open safety/relief valve during a transient. Such events were considered either to be within the capability of the makeup system or were covered by small-break LOCA analyses.

A reassessment of moderate frequency and infrequent events and their treatment by the NRC is necessary. In this case, it is apparent that greater awareness of the review areas and assumptions is necessary. In no case, however, would the present Standard Review Plan require that multiple failures similar to those associated with the TMI-2 event be considered as a design basis accident. Greater attention is needed in considering consequential failures and operator actions.

5. GENERAL DESIGN CRITERIA

Feedwater transients are anticipated operational occurrences since they are expected to occur one or more times during the life of a nuclear plant. The basic requirements for anticipated operational occurrences are given in General Design Criteria (GDC) 10 and 15. Additional requirements are specified in GDC 13 and 14.

GDC 10 requires that specified acceptable fuel design limits not be exceeded during anticipated operational occurrences. GDC-14 and GDC-15 require that the design of the reactor coolant pressure boundary should preclude abnormal leakage and the design conditions of the boundary should not be exceeded during anticipated operational occurrences. Additional requirements specified in GDC-13 are: "Instrumentation shall be provided to monitor variables and systems over their anticipated ranges...for anticipated operational occurrences...as appropriate to assure adequate safety...Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges." GDC 20 states the general requirements for protection systems, including the following: "The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specific acceptable fuel designs limits are not exceeded as a result of anticipated operational occurrences..." These criteria appear to have been met for BWR plants, even in the light of the TMI-2 experience.

6. REFERENCES

(1) NEDO-24154, Volume 1, 2, and 3, "One Dimensional Core Transient Model," General Electric Company, October 1978.

(2) NEDO-10802, "Analytical Methods of Plant Transient Evaluation for the General Electric Boiling Water Reactors," General Electric Company, February 1973.

APPENDIX E

OFFICE OF INSPECTION AND ENFORCEMENT BULLETINS (TMI-2)

1. INTRODUCTION

The NRC has a formal program within the Office of Inspection and Enforcement (IE) to feed back information to all operating reactor licensees regarding events of safety significance at operating reactors. When an event occurs at an individual plant that is of such safety significance as to require action by other licensees, an IE bulletin is issued.

As a result of the TMI-2 accident, a number of IE bulletins were issued. A listing of the bulletins that have been issued to date as a result of the TMI-2 accident is provided in Table E-1.

The followup actions required of licensees in response to the IE bulletins identified in Table E-1 can be separated into two categories: (1) those that required the review of information provided in the bulletins and assessments by the licensees as to the need for changes at their plants, and (2) those that required the implementation of changes in specific design features or operating procedures at their plants. Each of these categories of action for BWR plant licensees is discussed separately in Section 2 of this appendix. A summary of the NRC staff's evaluation to date of the actions taken by the licensees in response to IE Bulletin 79-08, the bulletin applicable to BWR plants, is provided in Section 3 of this appendix.

2. ACTIONS REQUIRED BY IE BULLETINS

2.1 Review Actions

IE Bulletin 79-05 was the first of a series of IE bulletins issued in connection with the TMI-2 accident. This bulletin was issued on April 1, 1979, and included a description of the initiating events as well as the course of subsequent events. In addition, this bulletin identified certain actions that were required to be taken by licensees with Babcock & Wilcox-designed plants.

IE Bulletin 79-05 served three primary purposes: (1) it informed all licensees of the events that transpired at TMI-2, (2) it initiated a review by licensees with Babcock & Wilcox-designed plants, and (3) it informed them of the need for certain changes at their plants. Subsequent bulletins [i.e., 79-05A, 79-05B, 79-05C, 79-06, 79-06A (Rev. 1), 79-06C, 79-06B, and 79-08] initiated similar reviews and identified more specific corrective measures to be taken in certain cases.

TABLE E-1

LISTING OF IE BULLETINS FOR THREE MILE ISLAND UNIT 2 ACCIDENT

Bulletin	Subject	Issue Date	Issued to Licensees
79-05	Nuclear Accident at Three Mile Island	4/1/79	All B&W designed power reactors with an operating license for action and all other power reactors for information
79-05A	Nuclear Accident Three Mile Island - Supplement	4/5/79	All B&W-designed power reactors with an operating license for action and all other power reactors for information
79-06	Review of Operational Errors and System Misalignments Identified during the the Three Mile Island Accident	4/11/79	All pressurized water reactors with an operating license (except B&W-designed reactors) for action and all other power reactors for information
79-06A	Review of Operational Errors and System Misalignments Identified During the Three Mile Island Accident (Replaced 79-06)	4/14/79	All Westinghouse-designed power reactors with an operating license for action and all other power reactors for information
79-06B	Review of Operational Errors and System Misalignments Identified During Three Mile Island Accident	4/14/79	All Combustion Engineering (CE)-designed power reactors with an operating license for action and all other power reactors for information
79-08	Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Accident	4/14/79	All boiling water reactors with an operating license for action and all other power reactors for information.
79-06A (Rev. 1)	Review of Operational Error and System Misalignment Identified During the Three Mile Accident. (Revised Items 3 and 13 of of Bulletin 79-06A)	4/18/79	All Westinghouse-designed power reactors with an operating license for action and and all other power reactors for information.
79-05B	Nuclear Accident at Three Mile Island	4/21/79	All B&W power reactors with an operating license for action and all other power reactors for information
79-05C & 79-06C	Nuclear Accident at Three Mile Island - Supplement	7/26/79	All pressurized water reactors with an operating license for action and all other power reactors for information.

On April 14, 1979, IE Bulletin 79-08, "Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident," was issued for action to all boiling water reactor plants with operating licenses and for information to all other plants with construction permits or operating licenses. A listing of the general review actions required by the licensees with boiling water reactor plants is presented in the paragraphs that follow. These general review actions have been abstracted from IE Bulletin 79-08. Actions required by IE Bulletin 79-08 that involve specific changes in the plant design or operating procedures are discussed in Section 2.2 of this appendix.

(1) Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 accident included in Enclosure 1 to IE Bulletin 79-05A. This review should be directed toward understanding: (a) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at the TMI-2 plant and other actions taken during the early phases of the accident; (b) the apparent operational errors which led to the eventual core damage; and (c) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

(2) Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

(3) Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status.

(4) Review all safety-related valve positions, positioning requirements, and positive controls to assure that valves remain positioned in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic surveillance to ensure that such valves are returned to their correct position following necessary manipulations and are maintained in their proper position during all operational modes.

(5) Review operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting, or other release of radioactive liquids and gases will not occur inadvertently.

(6) Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

2.2 Changes to Plant Design Features and Operating Procedures

In the days immediately following the issuance of IE Bulletin 79-05, the NRC received additional preliminary information related to the TMI-2 incident. Based on this information, the NRC identified six deficiencies consisting of human errors, design inadequacies, and mechanical failures as the likely candidates that led to the core damage and radiation releases at TMI-2. To assure that all the licensees were fully informed of these factors, followup bulletins were issued, beginning with IE Bulletin 79-05A on April 5, 1979, for licensees with Babcock & Wilcox-designed reactors and terminating with IE Bulletins 79-05C and 79-06C for all PWR plant licensees licensees as indicated in Table E-1.

In constrast to IE Bulletin 79-05, these later bulletins not only provided information for licensees to review, but also identified specific actions to be taken to reduce the likelihood of the type of event which occurred at TMI-2. The following is a listing of the types of actions to be taken by licensees with BWR plants. These actions have been abstracted from IE Bulletin 79-08.

(1) Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

(2) Operational personnel should be instructed to (a) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions, and (b) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

(3) Review and modify as necessary your maintenance and test procedures to ensure that they require; (a) verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service, (b) verification of the operability of all safety-related systems when they are returned to service following maintenance or testing, and (c) explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

(4) Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

(5) Propose changes, as required, to those Technical Specifications which must be modified as a result of implementing the items above.

3. EVALUATION OF LICENSEE RESPONSES TO IE BULLETINS

Our review of the licensee's responses to IE Bulletin 79-08 is complete. Requests for further information and clarification of individual licensee's responses have been made to facilitate the review of these responses.

Separate Bulletin Evaluation Reports (BEVRs) for each BWR operating plant are being prepared to document our evaluation of each licensee's response to IE Bulletin 79-08. These BEVRs state our conclusions regarding the licensee's responsiveness to each of the bulletin action items. They will also indicate whether the licensee (1) has correctly interpreted the bulletin, (2) has demonstrated its understanding of the concerns arising from the TMI-2 accident and its implications for the licensee's own operations, and (3) has provided added assurance for the protection of the public health and safety during plant operation.

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APPENDIX F

ANALYSIS

1. INTRODUCTION

Prior to the TMI-2 accident, slow system depressurization accidents, resulting from small breaks in the primary system, had not been subject to as detailed analytical studies similar to those devoted to large breaks. Typically, small breaks have been analyzed down to the smallest break size that would produce system depressurization without core uncovery, in accordance with the single failure criterion and other requirements imposed by 10 CFR 50.46. In general, while previous analyses were sufficient to show compliance with the requirements of 10 CFR 50.46, they failed to provide the depth of information needed to verify and develop operator guidelines for small breaks, as outlined by the NRC's Lessons Learned Task Force.(1)

Review of licensing models and their application to accidents have shown that: (1) small-break evaluations have received lower priority in the past, relative to large breaks, possibly resulting in inadequate analytical modeling techniques; (2) the most likely occurrence of a LOCA will be a small break, including transients resulting in a stuck-open relief valve; (3) plant and/or operator responses, can differ for large versus small-break LOCAs; and (4) actual operator actions and plant conditions may not follow the assumptions made in safety evaluations (e.g., operators may not actuate the ADS and other safety-related equipment at the assumed time).

There have been a few instances where BWRs have undergone transients in which operator action has defeated part of the ECC systems. Experience has also shown the high pressure systems failing to initiate, and the high pressure ECC systems isolating after initiation while operation was still required.

Reassessment of the failure modes for small-break LOCAs resulting from similar events (particularly in light of the TMI-2 accident), has led the staff and industry to a considerably broader interpretation (than previously held) of potential accident scenarios. The staff and the nuclear industry embarked on a detailed investigation of operator training and equipment reliability during abnormal conditions. The TMI-2 accident sequence clearly demonstrated that operators require additional training to detect abnormal system conditions and to respond appropriately.

The B&OTF met with the BWR plant licensees in June 1979, to discuss the short-term program for reviewing TMI-2 accident implications for BWR plants. Formal requests for information were sent to the licensees following the meeting.(2) In order to respond to our requests, the licensee's formed an Owners Group. The Owners Group investigated concerns relating to the instrumentation and systems relied upon by the reactor operators; investigated transients and equipment malfunctions experienced in operating reactors; and conducted detailed analytical evaluations of transient and small-break LOCAs. The purpose of these analyses was to evaluate system responses and the feedback relied upon by the operator, from which operator guidelines could be assessed.

The Owners Group's initial response to our concerns is documented in NEDO-24708.(3) This document describes BWR plant systems and, instrumentation, and provides small-break LOCA and transient analyses. The analyses assumed loss of feedwater and failure of the high pressure ECC systems. During our review, we requested additional information and documentation from the Owners Group.(4,5,6) Responses to our requests, not already received, are scheduled to be submitted in early 1980.

The following sections of this appendix address our evaluation of the analytical methodology used in developing the operator guidelines. Section 2 summarizes our conclusions and recommendations. Our review of the expected frequency of small-break LOCAs is discussed in Section 3. Section 3 also includes data from operating reactors, and an evaluation of anticipated transients. Our review of the small-break LOCA analyses is discussed in Section 4. Also addressed in Section 4 are the GE analytical methods used for evaluating system responses, the small-break LOCA analyses, computer model verification conducted to date, and natural circulation modes in a BWR. GE has not yet responded to the Michelson's concerns, as stated in Section 4.6. The independent audit evaluation of the GE computer model, performed at the Savannah River Laboratory under staff supervision is also discussed in Section 4. Section 5 contains the references used in this appendix.

As a result of our review of the analytical model used by GE for the Owners Group, and in light of the data and experience obtained from the TMI-2 accident, we also addressed the analytical assumptions used in licensing evaluation model analyses. Therefore, for completeness of review, we requested additional verification for the licensing models in order to assure that new concerns are incorporated into the licensing process and to determine if additional modifications are warranted.

2. SUMMARY OF ANALYSIS CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the most important conclusions and recommendations from each section of this appendix.

2.1 Small-Break LOCA Model Improvement and Verification

The small-break LOCA analysis methods used by GE are satisfactory for the purpose of predicting the sequence of events in BWR plants following a small-break LOCA. The results of the analyses can be used to develop improved emergency procedures and for the training of reactor operators. However, several individual models have been identified in Section 4.2, as requiring improvements or further confirmation.

GE has not provided integral experimental verification for their analytical small-break LOCA computer model. They have not participated in the Semiscale or LOFT small-break verification programs because of the atypicalities of the experiments to a BWR and their inability to model such systems with their small-break, fixed-node, computer code SAFE. At present only limited BWR small-break integral system data exists from which to verify the capability of GE's analytical models to perform small-break LOCA analyses.

To provide integral experimental verification of the SAFE code, the GE's Two-Loop Test Apparatus (TLTA) Program Management Group, consisting of EPRI, GE, and the NRC, have agreed to conduct small-break experiments for computer model verification. TLTA is the only existing BWR integral experiment available for simulating BWR blowdown phenomena. Due to scaling considerations such as jet pump geometry, the system can not adequately simulate reflooding phenomena for breaks located in the recirculation loops. GE provided the staff with pretest predictions and completed a small-break TLTA test on December 18, 1979. The data from this test may not be available until February 1980. Therefore, to assure that small-break models and the evaluation models for large breaks are adequate, we recommend the following:

(1) Test programs should be developed for the purpose of verifying GE's small-break LOCA models. We require pretest predictions of future test programs, designed to address our concerns, as described in Section 4 of this report.

(2) The analysis methods used for conducting Appendix K small-break LOCA evaluations should be revised for compliance with 10 CFR 50.46, documented, and submitted for NRC approval. Comparative analyses with TLTA tests should accompany the submittal.

(3) Plant-specific calculations, using a small-break model which has been approved by the NRC as complying with 10 CFR 50.46, should be submitted by all BWR plant licensees.

2.2 Conformance of Analyses to Expected Plant Responses

GE has performed a sufficient spectrum of small-break LOCA analyses to identify anticipated system performance for breaks in this range. The analyses performed by GE included transients resulting in a stuck-open relief valve. These analyses provide an adequate basis for developing guidelines for the small-break LOCA emergency procedures. The guidelines require the reactor operators to perform the following tasks, when confronted with a small-break LOCA:

(1) Verify that the plant has scrammed,

(2) Attempt to restart the high pressure safety systems they are if not already operating,

(3) Actuate the ADS when the mixture level decreases to Level 1 if there is no automatic actuation,

(4) Operate selected SRVs if the pool temperature exceeds a specified limit,

(5) Throttle or stop injection of ECC flow once reactor water level is reestablished to prevent overfilling the vessel, and

(6) Initiate the RHR system to attain a cold shutdown condition.

With the assumptions of proper operator actions and the worst single failure in the ECC systems, some small breaks are calculated to result in partial core uncovery. This includes transients which result in a stuck-open relief valve.

BWR plants have been shown to be able to withstand only one or two ADS actuations during their 40-year life. It is, therefore, possible that reactor operators may hesitate to actuate the ADS when required.

Licensing evaluations typically have assumed the loss of the high pressure injection systems as the worst single failure. However, the Technical Specifications allow plant operation for periods of 7 to 17 consecutive days with the high pressure systems out of service with and no limit on the accumulated outage time. Thus, system unavailability for extended periods of time is not precluded. Operational history to date does not appear to indicate abuse of the absence of cumulative outage requirements, but more data will be obtained for use in determining the need for cumulative requirements. Therefore, to assure that analyses are consistent with actual plant response, we recommend:

(1) For anticipated transients combined with the worst single failure and proper operator actions, licensees should demonstrate that the core remains covered or provide analyses to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve are to be included in this category.

(2) All cooling systems required to prevent core uncovery should be qualified as ECC systems. As an example, if the RCIC system is required, then it should be upgraded to qualify it as an ECC system (e.g., it should employ diverse actuation signals).

(3) Several components of the ECC system are permitted to have substantial outage times by the Technical Specifications (e.g., 72 hours for one diesel-generator, 14 days for HPCI the system). Additionally, there are no cumulative outage limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of the outages for all ECC systems. The report should also include the cause of the outage (e.g., controller failure or spurious isolation). The outage data for ECC components should include all outages for the last five years of operation. The end result should be the quantification of historical unreliability due to test and maintenance outages. This will establish if a need exists for cumulative outage requirements in Technical Specifications.

(4) Analyses to support depressurization modes other than the full actuation of the ADS should be provided. Slower depressurization would reduce the possibility of exceeding the vessel integrity limits by rapid cooldown.

(5) Plant simulators used for operator training should offer, as a minimum, the following small-break LOCA events:

(a) Continuous depressurization,
(b) Pressure stabilizing above the low pressure initiation setpoints,
(c) Repressurization, and
(d) Repressurization resulting in a stuck-open safety/relief valve.

Each of these cases should be simulated with breaks occurring at different locations in the system. Breaks in the steam line, recirculation lines, feedwater lines, and the control rod coolant lines should be modeled and incorporated in operator training programs. In addition to the usual single failures in the ECC and feedwater systems, complete loss of high pressure injection systems should also be simulated in conjunction with the above events. To verify that simulators used for operator training provide an adequate means of modeling adverse reactor response, selective unusual transients experienced during reactor operation should be programed into the simulator. The plant operator who experienced the transient should evaluate the simulator's ability to model plant characteristics. These transients should then be incorporated for operator training at all facilities.

(6) GE's small-break LOCA analyses relied on equipment which have not previously been identified as part of the reactor protection system or part of the engineered safety features systems. The systems used to terminate ECC flow on high vessel water level and the relief portion of the safety/relief valves fall into this

category. The reliability and redundancy of this equipment should be reviewed and upgraded, if needed, to provide appropriate protection. These systems should also be qualified for the post-LOCA environment.

2.3 Availability of HPCI, RCIC, and ADS

In addition to the single failure assumptions, two multiple failure assumptions were investigated:

(1) Loss of feedwater combined with the failure of the RCIC system and a single failure in the ECC system, and

(2) Isolation of the HPCI and RCIC systems during the course of a small-break LOCA. The isolation of the RCIC and HPCI systems could occur as a result of elbow taps indicating high flow during the initiation of the RCIC and the HPCI systems, which activate the steam turbine isolation valves.

Without operator action, both of these events result in a case in which neither the RCIC system nor the HPCI system is available. Results of analyses with stuck-open relief valves show that manual reinitiation of the HPCI system within approximately seven minutes after break initiation, will prevent core uncovery. Level 1 is reached at this time. The ADS will not actuate because a high containment pressure indication is not attained. The guidelines for the emergency procedures call for manual ADS initiation for such events. Unless the ADS is initiated within a relatively short time, the core could uncover and possibly become damaged. To improve the availability of required equipment, we recommend:

(1) The isolation logic of the HPCI and RCIC systems should be modified to prevent isolation when the break is not located in the HPCI or RCIC systems lines.

(2) ADS initiation should be automated for transients not resulting in a drywell pressure increase such as would occur during a stuck-open relief valve or LOCA outside containment.

(3) One of the two recommended operators should be designated to restart the high pressure ECC and the RCIC systems until recommendation (1) above is implemented.

2.4 Natural Circulation Under Degraded Conditions

A number of concerns related to decay heat removal following a very small-break LOCA, and other related items, were questioned by Mr. C. Michelson of TVA (Section 4.5). These concerns were identified for PWRs. GE was requested to evaluate these concerns as they apply to BWRs, and to assess the importance of natural circulation during a small-break LOCA in a BWR (see Reference 4). Due to manpower limitations, GE has not yet responded to Michelson's concerns. A brief description of natural circulation was addressed in NEDO-24708. The description was incomplete in that the natural circulation occuring in tests of isolation condensers was not referenced or addressed for the early-vintage BWR plants (i.e., BWR/1, BWR/2, and some BWR3 plantss). Therefore, we recommend the following:

(1) GE should provide a response to Michelson's concerns as they relate to BWR plants.

(2) Following a small-break LOCA, natural circulation plays an important role in depressurizing the reactor coolant system in BWR plants with isolation condensers. The various modes of natural circulation, including those with non-condensibles, should be demonstrated.

(3) If during natural circulation for degraded conditions, circulation between the core and the core bypass region is used for fuel bundle cooling, then such modes of circulation should be demonstrated experimentally. This will be addressed more fully in our review of inadequate core cooling.

2.5 Safety/Relief Valve Performance

The record of relief valve failures to close for all BWR plants in the past three years of operation is approximately 30 in 73 reactor years (0.41 failures/ reactor year). This indicates that the failure of a relief valve to close would be the most likely cause of a small-break LOCA. The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, four valves are challenged in each event, resulting in an equivalent of a 0.04 failure per challenge. The challenge rate can be reduced by the following:

(1) Additional anticipatory scram on loss of feedwater,

(2) Revised relief valve actuation setpoints,

(3) Increased ECC system flow,

(4) Lower operating pressures,

(5) Earlier initiation of ECC systems,

(6) Heat removal through emergency condensers,

(7) Offset valve setpoints to open less valves per challenge, and

(8) Installation of extra relief valves with a block or isolation valve feature to eliminate opening of the normal SRVs consistent with ASME code requirements.

The failure rate can be reduced as discussed in Section 2 of Appendix B to this report. Because SRVs are part of the reactor coolant pressure boundary and their performance record is rather poor, we recommend that:

(1) The frequency of relief valve challenges should be reduced, for example, by the methods noted above. GE should conduct a feasibility study to substantially (by an order of magnitude) reduce the challenge rate to the valves.

(2) Appropriate changes to the relief valves should be performed as recommended in Section 2 of Appendix B to this report in order to reduce the failure rate.

(3) All future relief valve challenges and failures should be reported to the NRC. This should include the prompt reporting of failures and inclusion of challenges in the annual report.

3. EXPECTED FREQUENCY OF SMALL-BREAK LOCAS

3.1 Introduction

The total expected frequency of a small-break LOCA is the sum of the probability of the events consisting of pipe ruptures and failure of a valve isolating the primary system to close. The range of the probability of small reactor coolant system ruptures based on pipe breaks is from 10^{-2} to 10^{-4} per reactor year with a mean value of 10^{-3} per reactor year as stated in WASH-1400.[7)] The probability of a small-break LOCA from valve failures was not given; however, the frequency of relief and safety valve failure was stated to be 10^{-2} per challenge.(8)

The TMI-2 accident was initiated by a loss of feedwater transient that caused a pressure increase in the primary system and the opening of a power-operated relief valve at the top of the pressurizer. The failure of the power-operated relief valve to reseat when the system depressurized produced the equivalent of a small-break LOCA. Transients in BWR plants have resulted in the equivalent of a small-break LOCA by virtue of a pressure increase to the relief valve setpoint and failure of the valve to reclose. We have evaluated the expected frequency of a stuck-open relief valve based on operating experience and predictions of plant transient response. These evaluations are based on a summary of operational data supplied by the Owners Group and the anticipated transients provided in NEDO-24708.

3.2 Data from Operating Reactors

Analyses presented in Section 2 of Appendix B to this report show that for all BWR plants in the last three years of operation, totaling 73 reactor years, there have been 187 cases of relief valve challenges. In these challenges, 30 failures to close have been recorded.

Based on 73 reactor years of operating experience, the resulting failure to close of a relief valve per reactor year is 0.41, which is approximately two orders of magnitude greater than a small-break LOCA resulting from pipe failure. The 187 cases of relief valve challenges in 73 reactor years is approximately 2.6 challenges per reactor year. The frequency of events table presented in NEDO-24708 shows that for anticipated transients that can cause a relief valve opening in BWR/4 and BWR/5 plants, one can expect 254 challenges in 40 years, or approximately 6.4 challenges per reactor year. This agrees with the actual three-year operating experience discussed above. It should be noted that each challenge may cause as few as one valve or as many as all the valves to actuate.

The GE report submitted for transient reclassification$^{(9)}$ also shows an expected frequency of occurrence for pressure increase transients of approximately 4.6 events per reactor year.

Since the total number of challenges is five to six to per year and because we do not expect the valves to open with every transient due to differences in plant design, core life, and bypass capacity, the transient evaluation from NEDO-24708 agrees with the plant operating data.

3.3 Evaluation of Anticipated Transients

GE performed analyses of anticipated transients using a modified version of its small-break LOCA code, SAFE. This code was used to identify those transients that are expected to open the relief valve for each BWR plant class, as well as for predicting the system response for use in developing the operator guidelines.

The normal code-used by GE for evaluating transient analyses are the REDY$^{(10)}$ or the ODYN$^{(11)}$ codes. These codes are used to predict the thermal-hydraulic and neutronic transient responses of reactors. The significant features of the ODYN code for predicting pressurization transients are:

(1) A one-dimensional neutron kinetics model is assumed with reactivity feedback from the control rods, voids, and Doppler effects.

(2) Improved steamline dynamics are used for evaluating system pressure responses.

(3) Principal controller features such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand are represented.

For evaluating pressurization transients, we believe the above analytical features to be essential for evaluating proper system responses. SAFE does not contain all of these features and GE did not present any verification of the SAFE code's ability to model pressurization events.

GE states that from past experience, the relief valves may open for the following transients: (1) turbine trip; (2) generator load rejection; (3) pressure regulator failure--closed; (4) feedwater controller failure--open; (5) trip of both recirculation pumps; (6) recirculation controller failure--closed; (7) loss of feedwater; (8) loss of auxiliary power; (9) closure of all main steam isolation valves; (10) loss of condenser vacuum; and (11) inadvertent relief valve opening. Besides the loss of feedwater event, GE has not provided analyses of other pressurization transients which open the relief valves.

Because of design differences, core exposure, and trip setpoints, it is not expected that every pressurization transient will challenge the relief valves.

3.4 Plant Modifications to Prevent Relief Valve Challenges

The probability of a small-break LOCA resulting from a stuck-open relief valve can be lowered by reducing relief valve challenges. Possible methods for reducing the relief valve challenge rate are discussed in the following paragraphs.

The challenge rate could be reduced by providing anticipatory scram signals on the feedwater pump trip similar to the scram signal derived from turbine stop valve closure on a turbine trip. This modification will reduce the reactor power quicker and thereby reduce the severity or magnitude of the pressure spike.

The relief valve setpoints could be revised upward to allow more margin to the relief valve opening setpoint. Another method to provide pressure margin is to lower the operating pressure. A combination of the relief valve setpoint and operating pressure will increase the plant's ability to withstand a pressure increase transient without causing the relief valve to open.

Another method that could be employed is to provide additional ECC flow to act as a heat sink (steam condenser) to accommodate the pressure increase due to swelling of the coolant. This could also be accomplished by modifying the plant instrumentation to provide earlier ECC system initiation. The combination of increased ECC flow at an earlier time in the transient could provide the necessary heat sink to absorb the power or pressure spike before the relief valve setpoint is reached.

An additional heat sink such as an emergency condenser similar to those used in early BWR plants, could be provided. Analyses show that for a loss of feedwater transient, the pressure increase is below the relief valve setpoint for the earlier BWR plants with isolation condensers.

The valve pressure setpoints could also be modified or offset such that fewer valves are challenged.

Plants could also be modified by installing new relief valves with normally-open isolation or block valves that would eliminate the opening of present safety/relief valves that may fail to close and cannot be isolated.

Any of the above plant modifications has the potential for reducing the number of challenges to the relief valves and thus reducing the probability of a small-break LOCA due to a stuck-open relief valve. The failure rate of the safety/relief valves can be reduced as discussed in Section 2 of Appendix B to this report.

3.5 Conclusions and Recommendations

3.5.1 Conclusions

The total expected frequency of a small-break LOCA consisting of failure to close of relief valves in all BWR plants in the last three years of operation is or 0.41 failures to close per reactor year. This is two orders of magnitude above the 10^{-3} failures/reactor year due to pipe ruptures which also contribute to the expected frequency of a small-break LOCA. The inventory loss from a stuck-open relief valve is of small enough magnitude so as not to lead to actuation of the ECC systems because plant makeup systems normally in use (such as the feedwater and control rod drive systems) will provide for the resultant coolant loss through the failed-open valve. However, many transients that lead to a relief valve challenge will cause an isolation with a resultant loss of feedwater and ECC systems will be actuated to recover the loss of inventory.

It must be stressed that BWR plants have direct vessel inventory measurements that actuate the ECC systems and the operators are trained to rely on redundant water level measurements to assure adequate core coverage.

3.5.2 Recommendations

(1) The frequency of relief valve challenges should be reduced by the methods noted above. GE should conduct a feasibility study to substantially (by an order of magnitude) reduce the challenge.

(2) Appropriate changes to the valve design should be performed as recommended in Section 2 of Appendix B to this report in order to reduce the failure rate.

(3) All future relief and safety valve challenges and failures should be reported to the NRC. This should include both prompt reporting of failures through licensee event reports and inclusion of challenges in the annual report.

4. SMALL-BREAK LOCA ANALYSES

4.1 Introduction

This section describes the small-break LOCA analyses submitted to the B&OTF by the Owners Group for the purpose of developing improved operator guidelines. We did not conduct a methods review; however, we did investigate the adequacy of the analytical model for simulating overall system responses to a small-break LOCA. The primary purpose of the review was to evaluate the model's ability to predict the sequence of events during a small-break LOCA and evaluate the parameters available to the reactor operator upon which manual actions are based (i.e., system pressure and reactor vessel level outside the core shroud). It was not our intent to assure that the fine details of a transient be modeled.

Section 4.2 addresses the analytical modeling in greater detail, noting possible modeling deficiencies or verification requirements. These concerns do not necessarily influence the approval of the code for developing operator guidelines. The majority of the concerns apply after operator actions should have occurred. However, these concerns may impact licensing evaluations and should, therefore, be addressed.

4.2 Analytical Methods

GE conducted a generic evaluation of postulated small-break LOCAs for BWR plants for the purpose of developing improved operator guidelines. The computer program used for the evaluations was a modified version of SAFE. The SAFE computer program has been approved for licensing calculations and is used to predict the long-term thermal hydraulic response for large and small-break LOCAs. Since SAFE is a fast-running computer program, and has undergone limited separate effects verification, GE concluded that a modified version of SAFE would be appropriate for developing operator guidelines for small break LOCAs. The analytical models used in the SAFE code are described in Reference 12. The evaluations performed have focused on an extensive small break spectrum (0.0001 to 0.5 square feet), which extended beyond the range of small breaks normally evaluated. During our evaluation of the SAFE computer program, a number of concerns were uncovered regarding the applicability of using SAFE for predicting consequences of small-break LOCAs. Our concerns consisted of the following:

(1) SAFE is a fixed-node computer program which has very coarse system noding (five nodes); does not distinguish the bypass inventory from the core inventory; does not model the recirculation lines, nor the recirculation pumps as separate nodes; does not model countercurrent flow limitation (CCFL) at the top of the core; injects LPCI system flow into the lower plenum rather than into the core bypass region for a BWR/5 plant or the recirculation lines for BWR/1 through BWR/4 plants and has not undergone nodalization studies for small-breaks LOCAs.

(2) SAFE has not been verified on small-break integral experiments. However, SAFE has been compared to separate effects tests i.e., blowdown from simplified pressure tanks.(13) The first integral small-break experiment was conducted during the latter part of December 1979 on the TLTA at San Jose, California. The data may not be available until February 1980. TLTA is a scaled BWR experimental apparatus, jointly sponsored by GE, EPRI, and the NRC.

(3) Modeling techniques using homogeneous-equilibrium assumptions, which determine the thermodynamic state between liquid and vapor, may not adequately predict system depressurization during ECC flow injection. Equilibrium assumptions have resulted in excessive depressurization rates which can affect ECC system intiation and flow rates.

(4) SAFE assumes that the primary system pressure is uniform. The neglect of localized pressure differentials resulting from steam condensation and liquid flashing may result in improper break flow quality which influences depressurization rate and system inventory. However, this may not play a significant role until core uncovery.

(5) Core coolant mixture level and heat transfer modeling are important parameters for small-break LOCAs. Separate effects data are available for justifying the models, but their use with applicable BWR plant geometry and applicable systematic interactions has not been evaluated.

(6) SAFE does not model the recirculation lines as separate nodes. The coolant inventory in the recirculation loops is added to the downcomer inventory. Thus, for LOCA analyses in which one or both of the recirculation loop inventory is not depleted, SAFE may improperly take credit for coolant inventory which is not available for core cooling.

(7) Experiences with homogeneous-equilibrium computer programs have shown instances where depressurization rates were overestimated during the injection of cold ECC flow. The excessive depressurization rates resulted in nonconservative ECC flow injection. At this time, it is not obvious when such behavior would occur.

4.2.1 Modifications to the SAFE Code

The SAFE code is used primarily for licensing calculations. Discussions were conducted between the staff and GE to evaluate its applicability for performing analyses to develop operator guidelines. GE, therefore, modified the SAFE code to enable it to provide a more realistic prediction of plant responses to a small-break LOCA.

Section 3.1.1.3 of NEDO-24708 discusses the GE modifications made to the SAFE analytical computer model. Topics of discussions included CCFL influences on small breaks, core bypass inventory modeling, decay heat modeling, core spray heat transfer modeling, extended nucleate heat transfer modeling, and ADS and feedwater system assumptions. The following subsections address our evaluation of the GE analytical models and assumptions.

4.2.2 Counter-Current Flow Limitation

CCFL is a phenomenon whereby the upward flow of steam can retard or totally stop the downward flow of liquid from penetrating an enclosed region. Since BWR fuel assemblies are designed with channel boxes, the steam generated by the fuel can, by momentum transfer and entrainment, limit the amount of coolant entering the fuel assemblies from above. Since the core spray inventory plays an important role in reflooding the core, CCFL has the potential of slowing and delaying the flooding rate of the system. CCFL effects are considered in the REFLOOD code, but are not modeled in SAFE.

NEDO-24708 provides a discussion demonstrating that steam generation at elevated pressures results in a lower volumetric steam flow when compared to the same generation rate at low pressures. GE, therefore, concluded that CCFL would play a neglegible role in a small-break LOCA since CCFL is predominantly a volumetric flow phenomenon. The staff noted that CCFL is a complex force balance phenomenon that is not exclusively dependent on volumetric flow, and could influence the outcome of a small break at elevated pressures. The influence of CCFL can result in changing the core heat transfer by influencing the mixture level in the core. This, in turn, can influence the system pressure and system inventory distribution. Therefore, for the analyses where core uncovery was calculated, GE should evaluate the steaming rate exiting the core and determine if CCFL should be considered for these cases.

We recommend that future experiments be designed to provide information demonstrating the influence of CCFL on large and small-break LOCAs since this may impact the severity of a LOCA.

4.2.3 Core Bypass Modeling

When evaluating small breaks, the SAFE code does not model the core bypass inventory as a separate node. Instead, the bypass inventory is incorporated into the core node. To justify the neglect of a separate bypass node, GE conducted comparative analyses, one with the bypass inventory added to the core (standard practice), and another with the bypass inventory added to the lower plenum. Comparisons showed a 14-second delay in depressurization, an increased core uncovery time of 30 seconds, and uncovery depth of an additional two-feet for the case where the bypass inventory was added to the lower plenum node. Based on this limited study, it is evident that the modeling of the bypass inventory could affect transient behavior. It may, therefore, be necessary to model the bypass region as a separate node. GE should provide additional justification for the bypass modeling assumption when providing future safety analyses.

4.2.4 Spray Heat Transfer Coefficient

The analytical evaluations performed were used in providing information for operator training and developing operator guidelines. The use of evaluation model assumptions are, therefore, not deemed necessary. Thus, for all analyses performed, GE increased the core spray heat transfer coefficient from the value of four, used in evaluation model calculations, to a best-estimate value of 12 Btu/hr-°F-ft^2. Results from the TLTA experimental facility showed these changes to be appropriate for these analyses.(14) We find this change acceptable.

4.2.5 Decay Heat Model

Since best estimate calculations were peformed, GE assumed best estimate decay heat (1978 ANS model) rather than the conservative evaluation model assumption. We find this acceptable.

4.2.6 Automatic Depressurization System

The ADS provides backup to the other high pressure ECC systems. It is used for depressurizing the reactor vessel so the low pressure ECC systems can be initiated. For evaluation model analyses, GE typically assumes one out of the three to eight ADS valves will not actuate when required. For the analyzed events, it was assumed that all ADS valves would actuate. GE provided sensitivity studies assuming zero, one, and two ADS valves inoperable. The results showed that, as the number of inoperable valves increased, the depressurization rate was slightly retarded. Even though the system response is somewhat retarded, the loss of one ADS valve had minimal influence on operator action or the information displayed to the operator. Therefore, the assumption of all ADS valves actuating is acceptable to the staff. It should be noted that the safety relief valves can be manually opened, one at a time, should the ADS valves fail to operate.

4.2.7 Feedwater Flow Modeling

For cases in which the feedwater flow was assumed to trip at time zero, GE used the Appendix K licensing assumption which conservatively ramps the flow to zero one second into the transient. When the feedwater was not assumed to be lost at time zero, a best-estimate behavior was assumed. The feedwater enthalpy, as well as the flow, remained constant until either the high level (Level 8) trip or the MSIV closure signal was actuated. The feedwater was then ramped to zero in five seconds. We find this modeling of the feedwater behavior acceptable.

4.2.8 Core Heat Transfer

GE assumed that the core remained in nucleate boiling until the local void fraction reached 99 percent. GE stated that the TLTA experimental facility provided data which supported the extended nucleate boiling model during high quality environment under low power generation.(14) This environment is expected during a small break where core uncovery occurs long after reactor scram. We questioned the use of nucleate boiling occurring up to 99 percent void fraction. Such an assumption would tend to evaporate or boil off more fluid from the core, thus lowering the system inventory level; but on the other hand, nucleate boiling could result in higher core mixture levels due to increased voiding. An analysis in the submittal compared the extended nucleate boiling heat transfer model with that of the approved Appendix K heat transfer model. The use of the extended nucleate boiling model showed little difference in the transient behavior and thus is acceptable for these analyses to develop guidelines for emergency procedures.

4.2.9 Reactor Vessel Internal Flows

In analyzing a LOCA, the SAFE computer program evaluates internal vessel flow rates from static pressure heads. These static pressure heads are a result of liquid columns providing the force for fluid to leave one region of the reactor vessel (e.g., downcomer) and enter another region (e.g., core). There is no other driving mechanism influencing internal flows within the system, other than the evaluation of thermodynamic properties (i.e., density, enthalpy). The limitation of modeling a system in this manner is that localized pressure gradients resulting from steam condensation due to ECC flow injection, or localized pressure increases due to liquid flashing in the core, are not accounted for in the evaluation of localized internal flows. Thus the distribution of coolant inventory within the system may not be adequately evaluated. As an example, core spray coolant may enter the hot core and flash, resulting in a localized pressure burst. The steam exiting the core could entrain the core spray inventory, and flow into the downcomer, and out the break. Thus, system inventory may be lower due to the redistribution of coolant within the vessel. This will also influence the system depressurization rate, since the break quality may be affected.

Another feature of this modeling technique is the neglect of internal pressure variations due to energy lost out the break. This results in a localized depressurization at the region nearest the break (i.e., downcomer pressure) and a redistribution of inventory within the vessel.

4.2.10 Conclusions and Recommendations

(1) The small-break LOCA analysis methods used by GE are satisfactory for the purpose of predicting the sequence of events in BWR plants following a small-break LOCA. In considering the use of the SAFE code to perform licensing calculations for very small-break LOCAs, the following items should be evaluated:

  (a) CCFL influence on small breaks during core uncovery,

  (b) Core bypass modeling,

(c) Neglect of pressure variations within the reactor vessel (other than static heads), and

(d) Integral experimental verification to assess the overall adequacy of the computer codes used in modeling a small-break LOCA (this may required long-term resolution).

(2) GE should provide an evaluation of the uncertainties in their ability to predict system pressures, mixture levels, clad temperatures (including lower plenum flashing), and reactor vessel inventory distribution.

(3) The GE model incorporates the recirculation line inventory into the downcomer. GE should show how this modeling technique influences small breaks when the inventory in one or both of the recirculation loops is not depleted.

(4) GE should investigate the influence of the homogeneous - equilibrium assumptions used in their LOCA codes and their influence on system depressurization rates.

(5) GE should re-evaluate their licensing models to assure compliance with 10 CFR 50.46. Documentation and changes to the analytical models should be submitted for NRC approval.

(6) Plant specific calculations, using the NRC approved licensing models, should be submitted to the NRC by each licensee with a BWR.

4.3 Small-Break LOCA Analytical Predictions

When developing operator guidelines for a nuclear power plant, the use of analytical computer models provide assurances that such actions will alleviate the consequence of an assumed event or accident. Section 3.1 of NEDO-24708 addresses the analytical results of computer simulated small-break and zero-break transients. The analytical transients, performed on the SAFE computer program, assumed expected (proper) automatic and manual actions for 36 postulated accidents. The 36 transients were simulated for BWR/2, BWR/4, and BWR/6 plants. For these analyses, GE's intent was not to evaluate the consequence (core temperature or damage) of postulated small-break LOCA transients, with varying availability of ECC systems, but to provide a prediction of the transient response (sequence of events) to a small-break LOCA. Thus the adequacy of operator guidelines for BWR plants could be developed or verified.

The following cases were evaluated:

(1) Small breaks with all makeup and ECC systems available,

(2) Small breaks with loss of normal makeup and high pressure ECC systems. In theory, the loss of the high pressure ECC systems in a BWR is similar to the loss of

auxiliary feedwater systems in a PWR, since both systems are utilized to depressurize the system.

(3) Zero break cases with loss of high pressure ECC systems, and

(4) Small breaks with a combined stuck-open relief valve and failure of the high pressure ECC systems.

Table F-1 lists the 36 analyses conducted by GE for the Owners Group. In these analyses, GE did not attempt to include transients resulting in inadequate core cooling conditions, nor did they address the maximum time available to an operator for performing manual actions. Such topics will be addressed as part of our inadequate core cooling reviews.

As discussed in Section 3 of this appendix, we have determined that transients resulting in a stuck-open relief valve fall into the catagory of anticipated operational occurrences, as defined in Appendix A to 10 CFR 50. The General Design Criteria require that acceptable fuel design limits not be exceeded for anticipated operational occurrences. We have also determined that mitigation of such transients with a stuck-open relief valve requires the use of single-train systems.

At present, the Standard Review Plan allows some fuel damage for anticipated transients coupled with a single failure provided a small fraction of the 10 CFR Part 100 criteria for doses are not exceeded. This is because a single failure of a safety system combined with an anticipated transient is considered to be an infrequent event.

Because of the relatively high frequency of occurrence of transients that can lead to a stuck-open relief valve, the high frequency of relief valves sticking open, and the reliance on a single high pressure safety system (i.e., the HPCI or HPCS systems), the staff should reconsider the acceptance criteria for transients coupled with a stuck-open relief valve and a single failure of the inventory maintenance system (i.e., the HPCI or HPCS systems). We believe that significant core damage should not occur for this event. However, this matter requires resolution within NRR. Until this is resolved the present Standard Review Plan criteria for infrequent incidents will be applied.

All systems required to prevent core damage must qualify as ECC systems. Thus, as an example, if the RCIC system is required for fulfilling the above requirement, then it must be upgraded to ECC system standards (i.e., diverse actuation signals). The GE small-break LOCA analyses rely on equipment which has not previously been identified as part of the reactor protection system or part of the engineered safety features. The systems used to terminate ECC and feedwater system flow on high vessel water level and the relief portion of the safety/relief valves fall into this category. The reliability and redundancy of this equipment should be reviewed and upgraded, if needed.

TABLE F-1

SMALL-BREAK LOCA ANALYTICAL PREDICTIONS

Break Location	Break Area	ECC Systems Available (Required)	Pressure Response Class*	BWR Type	Core Uncovery	Maximum Depth Of Core Uncovery (Ft.)	Total Core Uncovery Time (Sec.)	Submittal Figure Number**	ADS Actuation Time SEC. (M = Manual) (A = Automatic)
Recirculation Suction Line Break	0.0001	CRD + RCIC	1	4	NO	-	-	25	-
	0.001	HPCS	1	6	NO	-	-	39	-
	0.001	HPCI + LPCS	1/2	4	YES	0.9	10.	48	480.A
	0.001 + SORV	LPCI + LPCS	3/2	4	NO	-	-	54	410.A
	0.005	CRD + RCIC	1	4	NO	-	-	26	-
	0.005 + SORV	RCIC + LPCI + LPCS	3/2	4	NO	-	-	53	480.A
	0.005	HPCI	1	4	NO	-	-	36	-
	0.08	HPCI	2	4	NO	-	-	37	-
	0.1	RCIC + LPCI + LPCS	3/2	4	YES	12.	160.	27	165.A
	0.1	HPCS + LPCI + LPCS	2/3	6	YES	1.6	60.	40	165.A
	0.1	FDWR + LPCI + LPCS	2	4	YES	2.3	65.	46	2650.A
	0.1	LPCS	2	2	YES	12.	340.	50	110.A
	0.1	ALL ON	3/2	4	NO	-	-	20	-
	0.1	ALL ON	3/2	6	NO	-	-	21	-
	0.1	ALL ON	2	2	YES	1.5	36.	21	-
	0.1	LPCI + LPCS	1/2	4	YES	12.	180.	49	1860.A
	0.2	HPCI + LPCI + LPCS	2	4	YES	3.9	85.	38	170.A

TABLE F-1 (Continued)

Break Location	Break Area	ECC Systems Available (Required)	Pressure Response Class*	BWR Type	Core Uncovery	Maximum Depth Of Core Uncovery (Ft.)	Total Core Uncovery Time (Sec.)	Submittal Figure Number**	ADS Actuation Time SEC. (M = Manual) (A = Automatic)
Steam Line Break Inside Containment	0.0001	CRD + RCIC	1	4	NO	-	-	31	-
	0.05	CRD + RCIC	2	4	NO	-	-	32	-
	0.05	HPCI	2	4	NO	-	-	41	-
	0.1	FDWR + HPCI + LPCS	2	4	NO	-	-	47	1636.A
	0.1	LPCI + LPCS	3/2	4	YES	1.6	10.	51	420.A
	0.1	ALL ON	3/2	4	NO	-	-	23	-
	0.1	ALL ON	3	2	NO	-	-	22	-
	0.1	ALL ON	3/2	6	NO	-	-	24	-
	0.2	HPCI + LPCI + LPCS	3/2	4	NO	-	-	42	-
	0.2	HPCS	3/2	6	NO	-	-	43	-
	0.2	HPCS + LPCI + LPCS	3/2	6	NO	-	-	44	-
	0.2	RCIC + LPCI + LPCS	3/2	4	NO	-	-	33	420.A
Steam Line Break Outside Containment	0.0001	CRD + RCIC	1	4	NO	-	-	34	-
	0.05	HPCI	1	4	NO	-	-	45	-
	0.1	CRD + RCIC	1	4	NO	-	-	35	-
	0.1 + SORV	LPCI + LPCS	3/2	4	NO	-	-	55	480.M
	0.5	LPCI + LPCS	1/2	4	YES	4.4	360.	52	600.M
Recirculation Line Discharge Break	0.005	CRD + RCIC	1	4	NO	-	-	28	-

TABLE F-1 (Continued)

Break Location	Break Area	ECC Systems Available (Required)	Pressure Response Class*	BWR Type	Core Uncovery	Maximum Depth Of Core Uncovery (Ft.)	Total Core Uncovery Time (Sec.)	Submittal Figure Number**	ADS Actuation Time SEC. (M = Manual) (A = Automatic)
Core Spray Line Break	0.005	CRD + RCIC	1	4	NO	-	-	29	-
No Break	-	HPCI + LPCI + LPCS	1	4	NO	-	-	56	-
	-	LPCI + LPCS (10 min. manual ADS)	1/2	4	NO	-	-	57	600.M
	-	LPCI + LPCS (19 min. manual ADS)	1/2	4	YES	0.8	10	58	1140.M

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*Pressure Response Class 1 = Break size resulting in system pressurization to SRV set point
Class 2 = Break size resulting in pressure stabilizing at high vessel pressure
Class 3 = Break size resulting in continuous system depressurization

**NEDO-24708

The break areas analyzed in NEDO-24708, ranged from zero to 0.5 square feet. It was noted that breaks inside the containment provide similar plant transient characteristics for either steam or liquid breaks, when the break area is less than 0.005 square feet. Only for break sizes of 0.05 square feet or greater does the plant response to a steam line versus liquid line break exhibit different characteristics. The different characteristics are attributed to steam line breaks removing less mass inventory from the vessel. The net energy release of steam versus liquid breaks also contributes to a different depressurization rate. For small breaks, these differences typically result in liquid breaks requiring greater capacity makeup systems in order to maintain reactor vessel coolant inventory. As an example, the RCIC and the control rod drive systems are capable of maintaining system level for a 0.05 square feet area steam break, relative to a 0.005 square feet area liquid break. In the past, the RCIC and control rod drive systems were not considered ECC systems, but their use in these analyses demonstrated the inherent safety of the BWR plants for liquid breaks up to 0.005 square feet in area, since the use of the ECC systems is not required.

For situations where all high pressure systems (i.e., feedwater HPCI, HPCS, RCIC, and control rod drive systems) were assumed to be unavailable, the reactor vessel either depressurizes by virtue of the break size, or the ADS can be used to depressurize the system below 180 psi. At this pressure, the low pressure ECC systems (i.e., LPCI and LPCS systems) can be used to return the reactor vessel to a safe state.

The analyses performed represent a generic assessment for all GE-designed operating BWR plants. Since many GE-designed BWR plants have design similarities (i.e., BWR/3 through BWR/6 plants), and differ only in minor internal design and some ECC systems or penetrations, the plant behavior for many transients, and the required operator actions, will be similar. Thus, analyses for every operating plant were not deemed necessary, and a generic evaluation was conducted.

GE selected the BWR/4-218 plant as providing generic plant responses to a small-break transient. Where differences existed between plant types, a corresponding evaluation was performed (e.g., for a BWR/2 or a BWR/6 plant). Even though there are no BWR/6 plants in operation, the BWR/6 plant design was selected because its response is similar to a BWR/5 plant. Since the staff has a BWR/6 plant computer model already developed, the BWR/6 analyses were audited by the Savannah River Laboratory (see Section 4.7 of this appendix).

When performing the analyses, GE did not assume a loss of offsite power or loss of a diesel-generator. Analyses assuming failure of all high pressure systems were presented. Analyses with additional failures of low pressure ECC systems have been submitted and will be reviewed as part of our inadequate core cooling review.

When designing the transient matrix to be analyzed, three classes of break sizes were required by the staff. Class 1 breaks were break sizes which result in system repressurization to the safety/relief valve setpoints. The increase in pressure is due to core power generation exceeding the energy escaping through the break. Typically, such transients would result from breaks which are less than 0.005 square feet in area, or any break size occurring outside the containment. Breaks outside the containment result in the MSIVs isolating the core from the heat sink resulting in a pressure increase. The Class 2 breaks consist of break sizes approximately of 0.05 square feet where the energy exiting the break equals the energy generated in the core. This results in the reactor stabilizing at a high vessel pressure. Class 3 breaks are breaks typically greater than 0.1 square feet, which result in system depressurization through the break.

The analyses demonstrated that for the above classes of breaks, the following operator actions are required:

(1) Assure scram has occurred;

(2) Verify that the high pressure ECC systems are operating. If not, try to initiate the high pressure ECC systems;

(3) Verify that automatic ADS actuation occurs when the downcomer level decreases to Level 1. If automatic initiation has not occurred, actuate the ADS manually;

(4) Maintain surveillance on the suppression pool temperature. When the temperature exceeds a specified limit, actuate individual relief valves to depressurize the reactor vessel;

(5) Prevent reactor vessel overfill by throttling the low pressure systems or by manually controlling the high pressure systems;

(6) After adequate reactor water level is assured and the pressure has decreased, divert appropriate LPCI system pumps to the residual heat removal mode; and

(7) Proceed to the long term cooling mode of operation.

For transients resulting in a stuck-open relief valve, the break area increases by 0.1 square feet. Thus, a depressurization transient resulting from a stuck-open relief valve is equivalent to 0.1 square feet steam line break inside the containment. For this transient, operator action is required to initiate the ADS, because the drywell pressure is not increased (required for automatic ADS initiation) due to the stuck-open relief valve discharging directly into the wetwell. Once the ADS is actuated, the reactor vessel pressure is decreased and the system is refilled by the low pressure systems.

LOCAs resulting from a stuck-open relief valve, coincident with a loss of feedwater and the loss of the high pressure ECC systems are of major concern to this investigation. Conclusions derived in Section 3 of this appendix indicate that the most probable small-break accident is a depressurization transient resulting from a stuck-open relief valve. Depending on the assumptions made, such as the decay heat model used, a typical BWR/1 plant scenario for a loss of feedwater plus stuck-open relief valve event could exhibit the following system response: The Level 3 scram is reached 15 seconds after the loss of feedwater. Level 2 isolation is reached at 20 seconds and the operator must manually isolate the system within one hour if it does not isolate automatically and the control rod drive system flow fails. The system isolates (MSIVs close) at 30 seconds and the pressure increases to the isolation condenser setpoint. If the isolation condenser does not operate, the pressure will increase up to the lowest safety/relief setpoint at 180 seconds. If the safety/relief valve fails to reclose, the system will depressurize to the low pressure ECC system shutoff head at 450 seconds and the vessel will begin to reflood. After 650 seconds, the pressure reaches 150 psig and the operator places the RHR system into operation and controls reactor vessel water level by throttling the ECC system flows. Cold shutdown is achieved in 24 to 46 hours.

For the BWR/2 plant with a loss of feedwater plus stuck-open relief valve and the feedwater coolant injection system or isolation condenser unavailable, the system will respond as follows: The reactor will scram at 12 seconds; MSIV closure and LPCS system (partial logic) are initiated at 32 seconds; the MSIVs close at 35 seconds and pressure increases; the lowest safety/relief valve group opens at 73 seconds and all but one safety/relief valve reclose at 80 seconds. The water level reaches five feet above the top of the active fuel at 2-1/2 minutes and the operator must initiate the ADS to prevent core uncovery. The operator may also try to start the failed feedwater coolant injection system before reaching Level 1 at seven minutes to prevent core uncovery. If the operator initiates the ADS at 2-1/2 minutes (five feet above the top of the active fuel), the reactor will depressurize and the LPCS system flow will enter the vessel with the water level bottoming out and starting to rise at nine minutes. At 11 minutes into the accident, the reactor pressure will reach 150 psig and the operator will place the reactor in the shutdown cooling mode and throttle LPCS system flow. The reactor will reach cold shutdown in 24 to 48 hours.

For the BWR/4 plant with a loss of feedwater plus a stuck-open relief valve and no HPCI or RCIC systems available, the plant responds as follows: The reactor scrams and isolation, with the exception of the MSIVs, occurs at seven seconds. At 30 seconds, MSIV closure is initiated, the recirculation pumps are tripped, and the RCIC and HPCI system initiation level setpoints are reached. The MSIVs are fully closed at 35 seconds and the pressure begins to rise until the lowest pressure safety/relief valve group opens at 75 seconds. At 78 seconds, all but one safety/relief valve recloses and the reactor continues to depressurize. At 200 seconds, the water level decreases to five feet above top of the active fuel. The operator must manually initiate the ADS at this time or start the HPCI system prior to reaching Level 1 (at 7-1/2 minutes) to prevent core uncovery. If the ADS is initiated at 200 seconds, the low pressure ECC system flow will enter the core at 400 seconds. At 500 seconds the vessel water level reaches normal level and the pressure is less than 150 psig so the operator can initiate the RHR system. Cold shutdown is achieved in 24 to 48 hours.

For the BWR/5 plant with a loss of feedwater plus a stuck-open relief valve, and the HPCS and RCIC system unavailable, the plant responds as follows: A reactor scram is initiated at 25 seconds. MSIV closure is complete at 30 seconds and the system pressurizes. The lowest pressure safety/relief valve setpoint is reached at 55 seconds and the safety/relief valves reclose at 60 seconds except for the one stuck-open relief valve. The vessel water level decreases to five feet above the top of the active fuel at 250 seconds. The operator must manually initiate the ADS at this time to prevent core uncovery. The operator may prevent core uncovery if the HPCS system can be restarted before seven minutes (Level 1 is reached). If the ADS is initiated at 250 seconds, the low pressure ECC systems will inject flow into the vessel at 400 seconds and vessel level will recover at 600 seconds. The pressure at 600 seconds is below 150 psig and the operator places the RHR system in the cooling mode. If the operator had manually initiated the HPCS and RCIC systems at 250 seconds, the core level would have recovered at 650 seconds. At 1800 seconds the operator would place the system in the steam condensing mode until the pressure reaches 150 psig, at which time he will initiate RHR system cooling. Cold shutdown is achieved within 24 to 48 hours.

The operator action times for these are summarized in Table F-2.

From the above-described loss of feedwater transient, we have concluded that the initiation of the ADS should be automated for the following reasons:

(1) The time available to actuate the ADS in order to prevent core uncovery could be as short as three minutes after the relief valve fails in a stuck-open position with loss of high pressure ECC system.

(2) The loss of feedwater transient is an anticipated operational occurrence, as described in Section 3 of this appendix.

(3) The failure of a safety/relief valve has a high probability of occurrence (see Section 3 of this appendix).

(4) There have been occasions when both of the high pressure systems have failed.

(5) Manual action is required for pipe breaks outside containment.

4.3.1 Conclusions/Recommendations

The analyses performed are appropriate for showing the reactor response to a small break for the purpose of developing operator guidelines. The analyses described in NEDO-24708 provided the following information:

(1) The availability of an ADS plays a very crucial role as a backup system to the high pressure injection systems (i.e., the control rod drive coolant, RCIC, HPCS,

TABLE F-2

OPERATOR ACTION TIMES

Class		Normal LOFW Event
BWR/1	5 min. 2 hours	Manually control cooldown rate; Initiate RHR system
BWR/2	3 min. 2 hours	Initiate isolation condenser to control cooldown rate; Initiate RHR system
BWR/3	30 min. 2-1/2 hours	Initiate isolation condenser to control cooldown rate; Initiate RHR system
BWR/4	6 min. 30 min.	Manual control of level Use main condenser as heat sink
BWR/5	6.7 min. 30 min.	Manual control of level Use main condenser as heat sink

Class	LOFW/SORV	LOFW/SORV/No High Pressure Injection System Available	Remarks
BWR/1	Pressure below SRV	10 min. for RHR system	
BWR/2	P<Psrv	2.5 min. for ADS	Level 1 ADS
		7 min. for high pressure injection system	
		11 min. for RHR system	Pressure less than 150 psi
BWR/3	35 min. RHR system	3 min. ADS	5 ft. above the top of the active fuel
		7 min. for high pressure injection system restart	2 ft. above the top of the active fuel auto-initiation point
		11 min. for RHR system	Pressure less than 150 psi
BWR/4	6 min. level control	3.3 min. for ADS	5 ft. above the top of the active fuel
	30 min. steam condensing mode of RHR system	7.5 min. for high pressure injection system restart	Level 1 ADS auto-initiation point
		8 min. for RHR system	Pressure less than 150 psi
BWR/5	6.7 min. level control	4.2 min. for ADS	5 ft. above the top of the active fuel
	30 min. steam condensing	7 min. high pressure injection system restart	Level 1
		10 min. RHR system	Pressure less than 150 psi

and/or HPCI systems. The ADS and the high pressure systems were designed to prevent elevated pressure hangup, during which no low pressure ECC system flow can be delivered.

(2) The use of reactor vessel level indications are effective means of controlling the automatic makeup systems, including the ECC system, as long as adequate communication exists between the inner and outer core shroud regions.

(3) For breaks up to approximately 0.005 square feet in area, the normal make-up systems (i.e., the feedwater, control rod drive coolant, and RCIC systems) can maintain adequate core cooling without requiring the actuation of the high pressure ECC systems.

(4) Only during total failure of the high pressure injection systems, for breaks outside the containment, or during transients resulting in a stuck-open relief valve, is operator action required for initiating the ADS. For such transients, there is no high drywell pressure signal. Automatic actuation of the ADS requires coincident signals of:

    (a) High drywell pressure,
    (b) Low-low water level in the downcomer (Level 1), and
    (c) Indications that the low pressure ECC systems are operating (i.e., the LPCI or LPCS system).

    Should the wetwell fluid temperature (heat sink) exceed a given limit, then operator action is required for actuating individual relief valves in order to lower the system pressure and actuate the low pressure RHR system.

(5) Of the 36 small-break LOCA analyses performed, 11 transients either totally or partially uncovered the core. Core uncovery typically occurs as a result of ADS actuation. This does not necessarily result in excesss core temperatures, however. The uncovery period is typically short, with depth of uncovery between one and 4.5 feet.

    For cases resulting in core uncovery before ADS actuation, total core uncovery is likely. This will result for intermediate to large break sizes or during highly degradation conditions.

The analyses performed have not answered all of our concerns. GE should address the following open issues:

(1) The analyses provided by GE exhibited what appeared to be "unrealistic" oscillations in the mixture levels and internal flows. GE should evaluate the implication of the "unrealistic" oscillations observed in the analyses, and determine whether

operator confusion could result should such oscillations appear in the instrumentation during the course of an accident. These analyses should be submitted to the NRC staff.

(2) Degraded conditions in other than high pressure systems were not addressed in our review. Full credit was taken for all low pressure systems. GE has submitted additional analyses(17) for the degradation of the low pressure systems. These analyses will be reviewed as part of the inadequate core cooling review.

(3) For the events resulting in core uncovery, the peak clad temperatures were not evaluated. GE should submit heatup calculations to the NRC staff for all small-break LOCAs which result in core uncovery.

(4) Reactor operators have the ability to override the actuation of the ADS. GE has not provided the maximum delay available for actuating the ADS before licensing limits have been exceeded. They also have not addressed the time available for operator action before 10 CFR 50.46 criteria are exceeded. Such analyses should be submitted to the NRC staff.

(5) The GE analyses assumed average core conditions when evaluating system responses. GE should address the hot channel responses to small-break LOCAs.

(6) A BWR/6, Case 2 analysis, resulting in a pressure hangup was not submitted. GE should submit the analysis to the NRC staff.

(7) Analytical results demonstrating the influence of running the recirculation pumps have been submitted, however, the staff has not been able to review the submittal due to its late arrival.

(8) Breaks in the control rod drive lines, incor monitor vessel penetrations, drain lines, and standby liquid control lines, all located near the lower head, were not evaluated. GE should provide such analyses to the NRC staff.

(9) NEDO-24708 contains sequence of event tables for loss of feedwater transients. The loss of feedwater events were presented for all BWR classes. No justification was presented for the representative plant in each class and no analyses were provided for the derived sequence of event tables. GE also used BWR/2 plant analyses to derive the transient response for BWR/1 plants. The following information should be submitted to the NRC staff:

    (a) The analyses that were used to derive the sequence of event tables,

    (b) A description of how representative plants provide plant-specific transient response when the system characteristics of plants may differ within each class, and

(c) Justification of the use of BWR/2 plant analyses to derive BWR/1 plant responses to loss of feedwater transients.

(10) The analyses for the loss of feedwater event combined with a stuck-open relief valve and a failure of the high pressure ECC systems showed that manual operator action is needed within three minutes to prevent core uncovery. We recommend that the ADS be automated for small breaks which do not result in a high containment pressure. Reasons for this recommendation are based on the following:

(a) Loss of feedwater is an anticipated operational transient,

(b) Stuck-open relief valves are not uncommon,

(c) Instances have occurred where both the HPCI and RCIC systems have failed or were out of service, and

(d) Manual action to prevent core uncovery must be performed in a relatively short time.

(11) LOCA code predictions are used for programming reactor simulators. The simulators are then used in training reactor operators. We recommend that the following transients be modeled on reactor simulators and used in the training of the reactor operators:

(a) Small-break LOCAs resulting in a continuous depressurization,

(b) Small-break LOCAs resulting in the reactor vessel pressure stabilizing above the low pressure initiation setpoints,

(c) Small-break LOCAs resulting in repressurization of the reactor vessel, and

(d) Repressurization transients resulting in a stuck-open relief valve.

Each of these cases should be simulated with breaks occuring at different locations in the system. Breaks in the steam line, recirculation lines, feedwater lines, and the control rod drive coolant lines should be modeled and incorporated for operator training. In addition to the usual single failure assumptions in the ECC system and the feedwater systems, complete loss of the high pressure injection systems should also be simulated in conjunction with the above events. To verify that reactor simulators used for operator training provide an adequate means of modeling adverse reactor responses, selected unusual transients experienced during reactor operation should be programmed into the simulators. The plant operator who experienced the transient should evaluate the simulator's ability to model plant characteristics. These transients should then be incorporated for operator training at all applicable facilities.

(12) BWR plants have been shown to be able to withstand only one or two ADS actuations during their 40-year life. It is, therefore, possible that reactor operators may hesitate to actuate the ADS when required. Thus, analyses to support depressurization modes other than the full actuation of the ADS, should be provided. Slower depressurization would reduce the possibility of exceeding the vessel integrity limits resulting from rapid cooldown.

(13) Several components of the ECC systems are permitted to have substantial outage times (e.g., 72 hours for one diesel-generator and 14 days for the HPCI system) by the Technical Specifications. Additionally, there are no cumulative outage limitations for ECC systems. Licensees should submit a report detailing outage dates and the lengths of outages for all ECC systems. The report should also include the cause of the outage (e.g., controller failure, spurious isolation). The outage data for ECC system components should include all outages for the last five years of operation.

(14) Isolation of the HPCI and RCIC systems have occurred as a result of the elbow taps indicating high flow after system initiation. These systems should be modified to prevent the need for operator action to reinitiate the systems.

(15) To assure that adequate manpower is available for reinitiation of the ECC systems, there should be at least two operators in the control room during reactor operation. This requirement is expected to be superseded by requirements of the NRC TMI-2 Action Plan.

4.4 Computer Model Verification

To fully understand plant behavior resulting from small primary coolant system breaks, it is necessary to verify the calculational model used to predict such behavior. Section 3.1.1.4 of NEDO-24708 discusses the computer model verification conducted by the GE on its SAFE computer program. The verification studies consisted of single-volume depressurization experiments and references to large-break TLTA predictions. The single-volume depressurization tests provided a measure of the code's ability to conduct an inventory and system energy evaluation. It also provided assurances that the code can adequately evaluate mixture levels for a simplified geometry experiencing a break. Some integral large-break blowdown experiments have been evaluated on the TLTA experimental facility. The staff has not received detailed comparisons to demonstrate SAFE's capabilities. Nevertheless, no conclusions should be derived for their applicability to small breaks. In addition, it should not be concluded that a computer program can correctly simulate integral phenomena, such as that displayed in a small-break LOCA, solely on the basis that the component analytical models have been evaluated by separate effects tests. When integrated into one code, the "verified" parts may not necessarily interact appropriately or be applicable for all conditions. The primary means of verifying model interactions is through integral experimental verification.

4.4.1 Integral Small-Break Experiments

When analyzing a small break, it is not only imperative that system depressurization and total inventory be adequately evaluated, but the distribution of inventory inside the vessel is an extremely important parameter which must be accurately modeled. GE, EPRI and the NRC have recently conducted the first small-break integral experiment on the TLTA. The TLTA small-break transient is the first integral experiment to be used to verify the SAFE computer program for small-break LOCAs. Up to now, there have been no integral data from which to evaluate SAFE's capabilities for predicting small-break LOCAs for BWR plants.

The results of the first small-break experiment, conducted in the latter part of December 1979, are anticipated within 60 days after the experiment. The delay is due to the limited TLTA staffing and semi-manual data reduction required.

4.4.2 Modeling Assumptions to be Verified

The SAFE computer program consists of many simplifying assumptions when compared to similar PWR vendor codes. One such assumption is the treatment of pressure gradient distribution within the system. In analyzing a LOCA, the SAFE computer program evaluates the entire nuclear steam supply system as one boundary condition. That is to say, the system consists of a uniform thermodynamic pressure during a time increment in the transient.

SAFE does not evaluate a unique pressure for each of its five nodes. Thus, pressure gradients resulting from liquid vaporization within the core, steam condensation within a node, or localized pressure variation due to the presence of a break within a node are not evaluated. GE considers such pressure gradients as having only second-order effects on the internal system flow rates. According to GE, the primary influence of internal flow distribution result from static heads (pressure gradients from liquid columns). Should localized pressure variations provide a greater influence on internal flows, the system inventory distribution may not be accurately evaluated. A redistribution of the reactor vessel inventory could influence the break flow, the depressurization rate, and the core uncovery history during a LOCA.

4.4.3 Limitations of TLTA

GE has emphasized the importance of the TLTA atypicalities relative to a BWR for obtaining test results for model verification. The primary reason is the TLTA geometric atypicalities when compared to a BWR. One atypicality is TLTA's short jet pump which cannot maintain minimum core level during reflood as would be expected in an operating plant with a recirculation line break. Core reflood is limited to the top elevation of the jet pump. Therefore, TLTA's short jet pump will prevent adequate core cooling during the reflooding phase of the experiment. TLTA's atypical modeling of a single core channel does not provide multi-channel, multi-power assembly interactions. The modeling of the core bypass region is an additional atypicality. Modifications to correct some of these atypicalities are being investigated. The atypicality of the TLTA geometry is primarily due to scaling considerations. We agree with GE that TLTA does exhibit scaling limitations, however, the TLTA experimental apparatus was designed to provide phenomenological system responses similar to those expected in an operating reactor. We, therefore, conclude that atypicalities resulting from scaling deficiencies do not result in adequate justification that TLTA is not applicable for computer model verification. Therefore, GE should provide integral verification using the TLTA facility, or propose other integral facilities which could be used to verify their LOCA codes.

When evaluating transients that can result in a stuck-open relief valve, it is important that system conditions, time of ECC system initiation, stuck-open relief valve initiation, and recovery be accurately predicted with respect to reactor vessel water level and pressure. The SAFE code has not undergone verification of its capability to evaluate such events. This includes comparisons with the normally-used transient codes REDY and ODYN for applicable transients and to existing operating reactor transients resulting in relief valve actuation.

4.4.4 Conclusions and Recommendations

(1) The data comparisons provided in NEDO-24708 demonstrate that SAFE is capable of simulating simple experimental LOCA transients but additional verification should be provided to confirm that reactor vessel inventory distributions are adequately predicted for complex internal geometries during blowdown. Additional verification is anticipated by early 1980 using TLTA. To adequately assess the computer program's capabilities, the TLTA experiments must be accompanied by pretest predictions. Future experiments should be designed to provide challenges to the analytical tools and to evaluate their limitations and uncertainties.

(2) Since TLTA is not totally typical of a BWR, due to scaling and neutronic considerations, additional code verification should be conducted on SAFE, such as comparisons to plant startup test results and transients experienced at operating plants (i.e., a stuck-open relief valve) as recommended in NUREG-0578. Even though SAFE is primarily a LOCA code, it may be required for performing transient (no-break) analyses, and thus, the verification with transients and small-break LOCAs experienced in operating reactors would provide confirmation that its modeling is appropriate for evaluating plant response.

(3) The modified SAFE code should be compared to the normally-used codes REDY and ODYN or verified by comparison to reactor transients that have occurred during plant operation to evaluate the ability of the codes to predict challenges to the relief valves when evaluating transients and accidents for developing for guidelines for emergency procedures as required by Item 5 in Table B.2 of NUREG-0578.

4.5 Natural Circulation

The importance of natural circulation was highlighted by the TMI-2 accident. During abnormal reactor vessel conditions (i.e., reactor vessel isolation transients, accidents with loss of all high pressure make-up systems, and forced recirculation pump trip), the core of a BWR relies on internal natural circulation of the primary fluid to provide additional inventory from the downcomer and bypass region to cool the core. This natural circulation provides time for the operator and ECC systems to respond to prevent the core from exceeding 10 CFR 50.46 criteria. In addition, BWR plants with isolation condensers utilize natural circulation for system depressurization in a manner similar to PWRs.

4.5.1 Natural Circulation Under Normal Conditions

Section 3.3.1 of NEDO-24708 describes the reactor vessel internal flow patterns expected during natural circulation (recirculation pumps not running). During normal conditions (startup and shutdown), the primary natural circulation path is between the downcomer and the core (See Figure F-1a). In order to attain this circulation pattern, the two-phase mixture level must be higher than the bottom elevation of the steam separators. This provides liquid or two-phase mixture communication between the downcomer and the upper plenum. The driving force, providing the natural circulation, is primarily due to density variation between the core and the downcomer. The two-phase density in the upper plenum and the core region is less than the downcomer density resulting in a pressure gradient driving the flow from the downcomer, through the jet pumps, into the core and the core-bypass regions, and into the upper plenum. At the mixture level interface, steam escapes the system via the safety/relief valves, turbine bypass, or the turbine. The liquid, on the other hand, recirculates to the downcomer region.

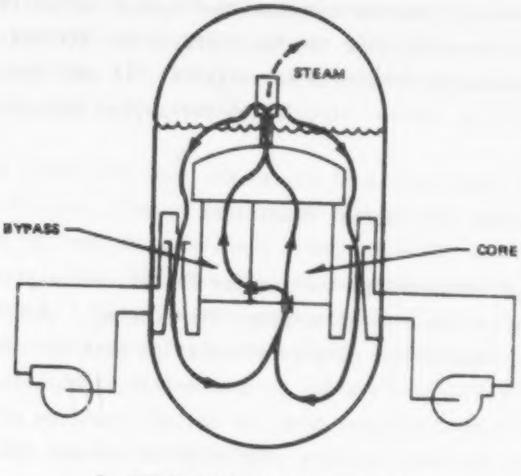
4.5.2 Natural Circulation Under Degraded Conditions

Should the net system inventory decrease, the level in the upper plenum will begin to fall. Eventually, the liquid communication between the upper plenum and the downcomer will be lost. The loss of this communication results in a new degraded circulation pattern between the core and core bypass regions as long as a water level is maintained in the upper plenum to replenish inventory lost to boil-off (see Figure F-1b).

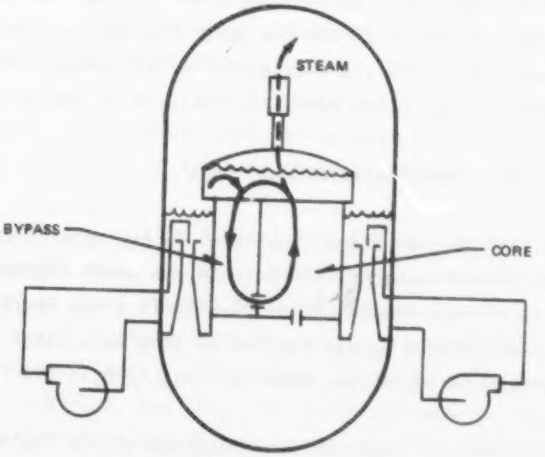
The degraded circulation pattern typifies a boiling pot with a limited water supply available in the downcomer, core, and the core bypass region. Assuming loss of all makeup systems or degradation to a degree which cannot equal or exceed the boil-off rate, the downcomer level will decrease until the jet pumps uncover. The downcomer inventory, to this elevation, is available for core cooling.

Inside the shroud (core-upper plenum region), during the degraded circulation period, an internal natural circulation pattern is developed between the core and the core-bypass region (see Figure F-1b). This circulation pattern may exist during the time

Figure F-1


STEAM
BYPASS
CORE

A – NORMAL NATURAL CIRCULATION


STEAM
BYPASS
CORE

B – INTERNAL LOOP CIRCULATION

Figure F-1 Natural Circulation Under Degraded Conditions the upper plenum/downcomer liquid communication (level) is lost until the upper plenum mixture level decreases to the upper tie plate elevation where the core/core- bypass communication is lost. From that point on, no natural circulation patterns would exist which continuously circulates liquid between the core and the bypass region. The remaining core-bypass inventory will, to some degree, drain into the core until the bypass mixture elevation decreases to the bottom of the core elevation.

GE referenced experimental data at 1000 psia pressure showing that dryout conditions will not occur for a fuel bundle with no inlet flow, when the power is less than 400 kw provided a mixture level exists in the upper plenum. For a bundle power of six mw, which is typical of a hot bundle in a BWR, the decay power will be less than 400 kw approximately ten seconds after a scram. During this period, natural circulation or pump coast down will exist. As long as water is available in the upper plenum to replenish the liquid inventory loss due to core boil-off, dryout would not occur. Thus, whenever an upper plenum mixture level is present, adequate core cooling is assured. Once the mixture level decreases into the core region, natural circulation of liquid will cease.

Our conclusions and recommendations are as follows:

(1) At present, we foresee no problem which will prevent natural circulation within the reactor vessel as long as adequate communication exists between the inner and outer shroud regions (non-jet pump plants can isolate communication between the inner and outer core shroud regions).

(2) GE should document the experimental data referenced that demonstrated that dryout will not occur for a bundle with zero inlet flow, covered by a mixture level in the upper plenum, and whose power is less than 400 kw.

4.5.3 Natural Circulation for Depressurization

Some operating plants of the BWR/1 through BWR/3 designs, rely on isolation condensers to depressurize the system during reactor vessel isolation. The depressurization process is accomplished by extracting steam upstream of the isolation valve, condensing the steam via a heat exchanger, and returning the condensate to the recirculation lines of the reactor vessel. This process of condensing reactor vessel steam, thus reducing vessel pressure, relies totally on natural circulation in the primary side. The process is passive in that no pumps force the extraction of steam and injection of condensate back into the reactor.

Should the process of natural circulation for the purpose of depressurizing the reactor be interrupted, then the decay heat generated by the core would result in a system pressure increase, thereby challenging the safety/relief valves. Since it is desired to reduce the challenge frequency of the safety/relief valves, the reliability of the isolation condenser should be verified for all anticipated modes.

Concerns related to natural circulation in PWRs have been raised by Mr. C. Michelson of the Tennessee Valley Authority. These concerns, as related to BWRs, are discussed in Section 4.6 of this appendix.

GE should provide a detailed evaluation of natural circulation and its effect on system depressurization. If natural circulation is relied upon to remove decay heat and prevent challenging the safety/relief valves, the various modes of natural circulation which are expected to play a significant role in plant response following a small-break LOCA or vessel isolation should be justified. This should include appropriate experimental verification, if needed.

4.6 Michelson Concerns

A number of concerns related to decay heat removal following a very small break LOCA and other related items were questioned by Mr. C. Michelson of the Tennessee Valley Authority. These concerns were identified for PWRs. GE was requested to evaluate these concerns as they apply to BWRs and to assess the importance of natural circulation during a small-break LOCA in BWRs.(4) GE has not yet responded to the Michelson concerns. A brief description of natural circulation was addressed in NEDO-24708. The submittal was incomplete, however, in that natural circulation for purpose of depressurizing the reactor vessel was not addressed. GE should provide a response to the Michelson concerns as they relate to BWR plants.

4.7 Staff Audit Calculation

4.7.1 Introduction

Increased attention has been focused on small-break LOCA behavior and overall system response to such breaks as a result of the TMI-2 accident. The primary purpose of the audit calculations is to provide reasonable assurance that the calculated system response obtained from the SAFE 2 computer program can be used as a basis for guidelines for the development of plant emergency procedures to be used to detect and to mitigate the consequences of a small-break LOCA.

Four loss-of-coolant accident cases were studied. Three of the cases involve breaks in the suction side of the recirculation line and the remaining case concerns a steam line break inside containment. The recirculation line break cases differ from one another with respect to either break size or assumptions regarding the availability of the various ECC systems. The four cases are as follows:

Case #1 - 0.1 square foot suction line break with all systems operable
Case #2 - 0.1 square foot suction line break with the HPCS, LPCS, and LPCI systems inoperable
Case #3 - 0.2 square foot steam line break with the HPCS system available
Case #4 - 0.001 square foot suction line break with the HPCS system available

The model and assumptions used in the staff analyses are described below in Section 4.7.2, of this appendix. The differences between the RELAP 4 and the SAFE 2 analyses which have a significant effect on the calculated transients are discussed in Section 4.7.3 of this appendix. The results of the analyses are presented in Section 4.7.4 of this appendix.

4.7.2 B&OTF Audit Model and Assumptions

The WRAP computer package was used to perform the B&OTF analyses.(15) The RELAP 4/MOD 5 computer program was used to perform the blowdown analyses.

The original nodalization from which the final model is derived was developed by the Idaho National Engineering Laboratory (INEL) for use in the large break analysis of BWR/-6-218 plant.(16)

Since small-break LOCAs are characterized by less severe pressure and temperature gradients in the reactor system than are large break LOCAs, a coarser mesh was used for the calculation to reduce computer time. The volume nodalization used for these studies (Figure F-2) involved the following modifications:

(1) The hot core channel, average core channel and nonheated portion of the core are collapsed to one volume,

(2) Eight core heat slabs are used,

(3) The core bypass region and guide tubes are collapsed to one volume,

(4) The break volume and suction line in broken loop are combined, and

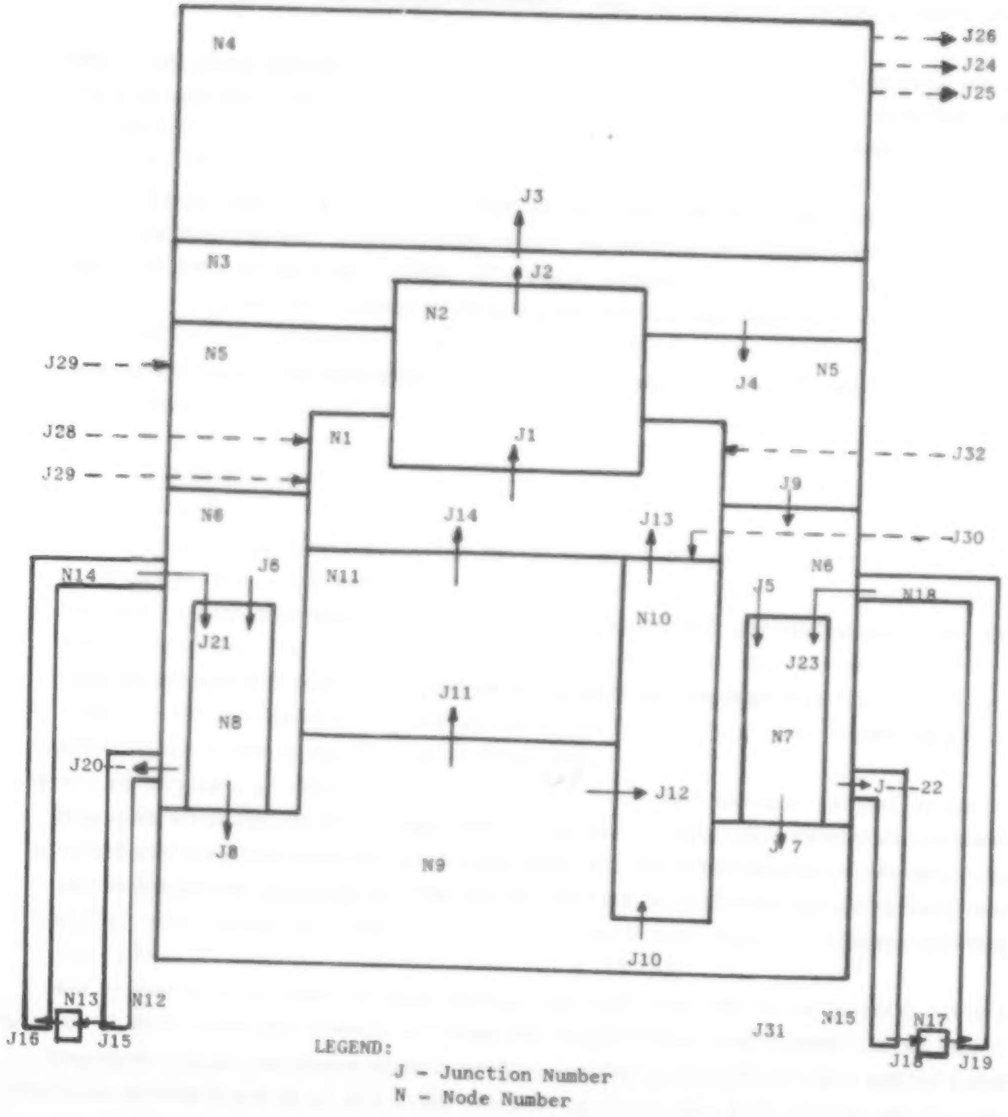
(5) The two volumes representing the intact recirculation loop discharge line are combined.

Volume collapsing involves removal of many junctions. In order to preserve the correct hydraulic representation, the inertia of any new junction is set equal to the sum of all functions in the series which are replaced. Also, the new form loss coefficients are computed by the summation of the old coefficients weighted by the square of the junction areas.

A brief description of the more important options used in these calculations is presented below. Since these calculations are meant for direct comparison with GE calculations rather than for licensing concerns, best-estimate models are used. In general, most of the options used were obtained from the BWR/6-218 large break problem developed by INEL. Some additional changes were made based on experience gained while performing the GE analyses and based on experience gained during the audit analyses for the PWR vendors.

Figure F-2

Note: Junction 17 is break
Node 16 is containment


N4
J26
J24
J25
J3
N3
J2
N2
J29
N5
J4
N5
J28
N1
J1
J32
J29
J9
N6
J14
J13
J30
N14
J8
N11
N6
N18
J21
N10
J5
J23
J11
N8
N7
J20
J12
J22
J8
N9
J7
J10
N13
N12
J16
J15
J31
N15
N17
J18
J19

LEGEND:
J - Junction Number
N - Node Number

Figure F-2 WRAP Nodalization for BWR-6 Small Break LOCA Analyses

Bubble Rise

The Wilson bubble rise model is used in the core, core bypass, steamdome, steam separator, downcomer volumes, and upper and lower plena (Volumes 1-6 and 9-11) to determine mixture level. A gradient of 0.0 is used in conjunction with the bubble rise model. The containment is modeled with instant phase separation (bubble velocity = 1×10^6 feet/second and gradient = 0.0). Gradient, as discussed above, represents the bubble density distribution within the mixture level. A gradient of zero represents a uniform bubble distribution within the mixture.

Slip

Slip is accounted for at Junctions 1-4, 9, 11, 13 and 14. The normal slip correlation is used for low volumetric fluxes with all default values used for the parameters except for the exponent which is 1.75 (from INEL input) rather than the default value of 1.25. For high volumetric fluxes, the dispersed slip flow correlation is used. All multipliers for this correlation are equal to unity which are the recommended best-estimate values.

The IAMBLO parameter is used for volume pairs associated with each junction where slip is specified except for the upper plenum-bypass and upper downcomer steam separator pairs. This is necessary because the IAMBLO option allows only one volume below any other volume. The IAMBLO option is utilized to prevent "pancaking" between stacked volumes, i.e., alternate liquid/steam stacking in vertical volumes. Should a volume contain a mixture level, then all volumes stacked below it will not evaluate a mixture level and will be treated as a homogeneous volume if the IAMBLO option is selected.

The Wallis flooding correlation was used for all cases and employed coefficients which were provided by GE.

Critical Flow

The critical flow models used are Moody for saturated flow and Henry-Fauske for subcooled flow. All discharge coefficient multipliers were 1.0.

Decay Heat

The October 1971 ANS standard is used with a multiplier of 1.0.

Momentum Equations

The compressible single-stream flow form of the momentum equation (MVMIX = 0) is employed at all junctions except for:

(1) Jet pump inlet junctions (MVMIX = 1 at drive junctions, MVMIX = 2 at suction junctions - this automatically invokes the jet pump smoothing correction);

(2) Break function (MVMIX = 3);

(3) Critical junctions (fills or leaks, MVMIX = 3 or -2); and

(4) Non-principal flow paths (MVMIX = 3).

When the steam dome pressure drops below 75 psia, the momentum equations used for all junctions is the incompressible form (MVMIX = 3).

Heat Transfer

The Groeneveld 5.9 film boiling correlation is used (RELAP input option). Local quality calculations are performed for all core slabs.

Trip Settings

Most of the safety systems are initiated by signals derived from measurement of the liquid level in the reactor vessel. The temporal system response to a LOCA is sensitive not only to the time at which fluid begins entering the vessel from external sources but even more sensitive to initiation or failure to initiate a particular system. Thus, when comparing independent calculations, it is important that the trip levels be consistent. This section describes the "standard" trip level number,(18) the elevation of this level above the top of the core, and the elevation relative to the base of the respective volume in the WRAP nodalization.

Level Number	Feet Above Top of Core	Elevation in WRAP
1	~ 1.5	20.265 feet relative to lower downcomer
2	~ 10.	5.032 feet relative to middle downcomer
3	~ 14.	3.487 feet relative to upper downcomer
8	~ 21.	10.712 feet relative to upper downcomer

Each emergency system modeled in the problem input is initiated when a given criterion is satisfied by a particular system parameter. A description follows of the various available systems corresponding to the WRAP analysis.

(1) HPCS - This system is initiated at t = 0.001 seconds implying the assumption of a drywell high pressure signal. Associated with this trip is a 27 second time delay before injection of water actually begins. This simulates the time necessary for the system to reach operating conditions. The HPCS system flow enters the system in the upper plenum.

(2) Recirculation Flow - The recirculation pumps trip on a Level 2 liquid level. There are also flow restrictors associated with each loop which begin constricting the flow area of the line 15 seconds after the temperature difference between the steam dome and the suction side of the respective loop becomes less than 8.5 Fahrenheit degrees. The flow restrictors are allowed 120 seconds to reduce the flow area to 77.78 percent of the original area.

(3) MSIV - This valve closes when the liquid level reaches Level 2 or when the steam dome pressure drops below 850 psia. The flow area decreases to zero over a three second period. The steam flow prior to isolation is described by a pressure dependent (negative) fill table.

(4) Control Rod Drive - The fluid flow from this system enters at the bottom of the core bypass region. It remains at full flow (7.5 pounds/second) throughout the transient.

(5) Feedwater Flow - Feedwater is assumed to have a constant enthalpy and flow rate until valved off. Flow stops when either a Level 8 liquid level is reached or when the steam dome pressure drops below 850 psia. The feedwater valves are allowed five seconds to close. Feedwater enters the system at top of middle downcomer.

(6) Scram - High drywell pressure is assumed by GE to occur at t=0.001 seconds so the reactor is scrammed at the beginning of the transient.

(7) LPCS - The LPCS system initiates on a high drywell pressure signal at t=0.001 seconds with an accompanying 27 second time delay. The spray starts injecting fluid into the system when the pressure at the entrance point, the upper plenum, becomes less than 275 psi.

(8) LPCI - The LPCI system is tripped in an identical fashion as the LPCS system The flow actually begins when the injection point, the top of the bypass region, is less than 180 psia.

(9) ADS - The ADS begins its initiation sequence on a Level 1 liquid level signal. This begins a 120-second countdown sequence until the ADS valve is actually opened. The ADS flow passes from the steam dome to the containment.

(10) Safety/relief/valve - The safety/relief valve is set to open when the pressure difference between the steamdome and containment is greater than 1095 psia. Flow through the safety/relief valve travels from the steam dome to the containment.

(11) RCIC - The RCIC system initiates a 30-second countdown on Level 2 liquid level. A constant flow rate and enthalpy is assumed. The system will be shut off on a Level 8 liquid level or a low system pressure (pressure less than 165 psia) signal.

4.7.3 Model and Modeling Differences

The SAFE computer program models the reactor vessel with a single, spacially-uniform pressure using five fluid regions. Because SAFE is intended to predict long-term transients, which are typical of small breaks, local effects are generally ignored and inertial terms are not considered. The steam separators are assumed to have no carry-under or carryover and homogeneous, thermal equilibrium fluid model is used. Relative flow between steam and liquid is based on the Wilson correlation.

The level swell model used in SAFE is a geometric relationship between level and volume, and is an input table into the program. The volume which the homogeneous fluid mixture occupies determines the level. This level is then used to actuate the various trips. The calculation of the level, and the subsequent trip actuations, becomes a key factor in comparing the RELAP 4 and SAFE analyses. The bubble escape velocity from the mixture was determined by the Wilson bubble rise model.

An example of the differences in the level calculations is seen in the analysis of the steam line break. For this case, the staff analysis calculated an ADS trip at Level 1. This emphasizes the importance of the level calculation and subsequent trip actuation. In the staff model, systems are tripped on mixture levels in the downcomer region. However, when using the IAMBLO parameter in this region, the mixture levels are artifically expanded if the volume above has liquid in it. Thus mixture level trips are inappropriate. Using liquid level trips in these calculations caused the ADS to trip in all four problems. However, in Cases 1 and 4, the liquid level just barely reached the trip level before increasing again whereas GE did not activate the ADS activate. The ADS trip was inactivated for these analyses, and the transients were re-run. The mixture level used in RELAP 4 is higher than the corresponding liquid level, but it is not certain how much lower the RELAP 4 level should be for trip actuation.

Counter current flow limitation (CCFL) seems to produce, and enhance, core uncovery in the staff analyses. This effect is not modeled by GE in their SAFE code. CCFL does influence the core uncovery but, for the transients audited, CCFL does not influence the development of the guidelines.

Some calculational difficulties were observed in the staff analyses at low pressures, less than 100 psia. The sudden change in the momentum equation from the compressible to the incompressible form may cause instabilities in the calculations.

4.7.4 Audit Analyses Comparisons

4.7.4.1 Case 1

This case represents the expected response of safety systems to a small recirculation line break. A 0.1 ft^2 break is simulated at the bottom of the suction side of the recirculation line and the assumption is made that all safety systems operate properly. Safety systems which are involved in this problem are the HPCS, RCIC, LPCS, ADS and

best copy available

LPCI. Feedwater is assumed not to be lost until valved off due to high liquid level or low reactor vessel pressure. ECC systems are modeled by pressure dependent fill tables. Containment is assumed to remain at initial conditions.

Figures F3 through F-7 present comparisons between the staff and the GE analyses.

The break and subsequent loss of fluid is followed by a sharp depressurization in the staff analysis which is halted at 12 seconds upon isolation of the main steam line. Recirculation pumps are also tripped at this time and begin their coast down. Since the steam still being created in the core cannot easily escape from the system, a pressure rise occurs in the steam dome. At 27 seconds, there is a small interruption of the pressure increase due to the initiation of the HPCS system. The RCIC system initiates at 42 seconds also injecting water into the upper plenum. The GE results do not show a pressure rise after isolation, as a result of neglecting inertial effects.

The pressure in the steam dome continues increasing in the staff analysis until at 55 seconds all the liquid has been forced out of the volume. At this time the steam can escape from the steam dome into the upper downcomer. Also, due to the high pressure, there is very little steam being generated in the core, as shown in Figure F-4. Thus, a slow depressurization begins as condensation and break flow tend to depressurize the vessel while the free volume available for the steam is being reduced by the flow of liquid into the system via the feedwater, HPCS, RCIC, and CRD systems. At 68.5 seconds, the collapsed liquid level in the upper downcomer has reached the high level trip mark which shuts off the feedwater and RCIC systems. After these systems are isolated, the loss of mass out the break, (see Figure F-5) which is still subcooled flow, far exceeds the combined inlet flow rate of the remaining fill systems. Thus a rapid depressurization begins as the steam expands. The rate slows as the core saturates again producing more steam.

At 175 seconds, reverse flow through the jet pumps in the broken loop brings fluid from the lower plenum into the discharge line and out the break. This causes a leveling off of the break flow despite the fact that it saturates at this time. This also causes a reduction in the depressurization rate of the system. This rate continues until 780 seconds when the break junction quality drops to zero. At this point the pressure levels off at 275 psia for about 75 seconds at which point it begins to drift down again as the system is flooding. At 1050 seconds, the upper downcomer has filled to the top of the steam separator and liquid flows into the separator volume. This causes condensation in the volume and a sudden pressure drop. This depressurization interrupts the flow pattern that had developed inside the shroud with water flowing up through the core into the upper plenum, mixing with the HPCS and LPCS system fluid, flowing down through the bypass region into the lower plenum and back through the core with some fluid branching off through the jet pumps. The depressurization caused the flow to reverse in the core and continue up into the downcomer region. Since the core is in the subcooled convection heat transfer regime, this stagnation and reversal of flow reduces the heat transfer coefficient and results in an increase in clad temperature. The temperature in the middle of the core rises from 330 degrees Fahrenheit to 375 degrees Fahrenheit and then decreases again as the core returns to positive flow.

Figure F-3

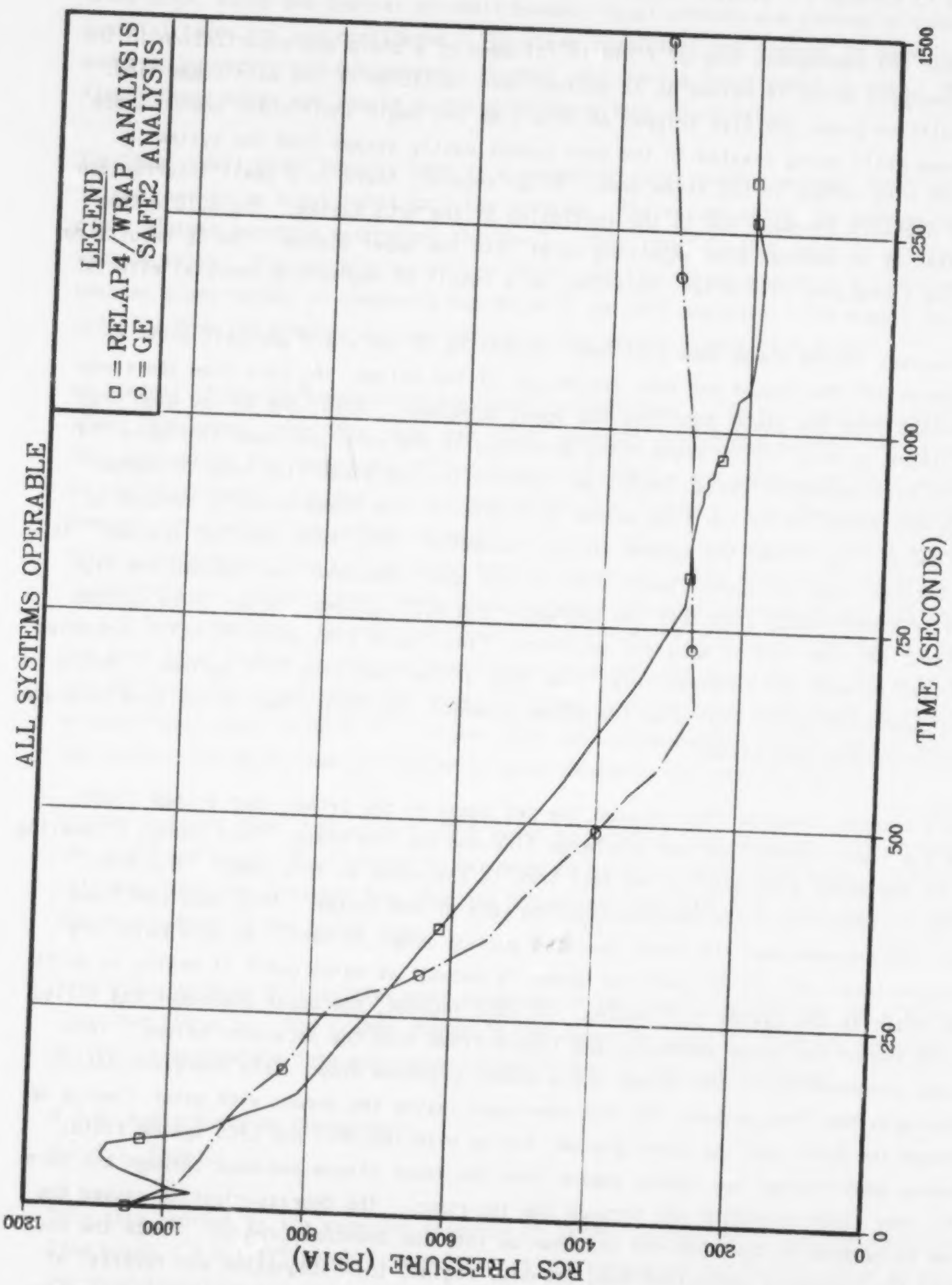


Figure F-3 GE BWR-6 0.1 Ft**2 Suction Line Break

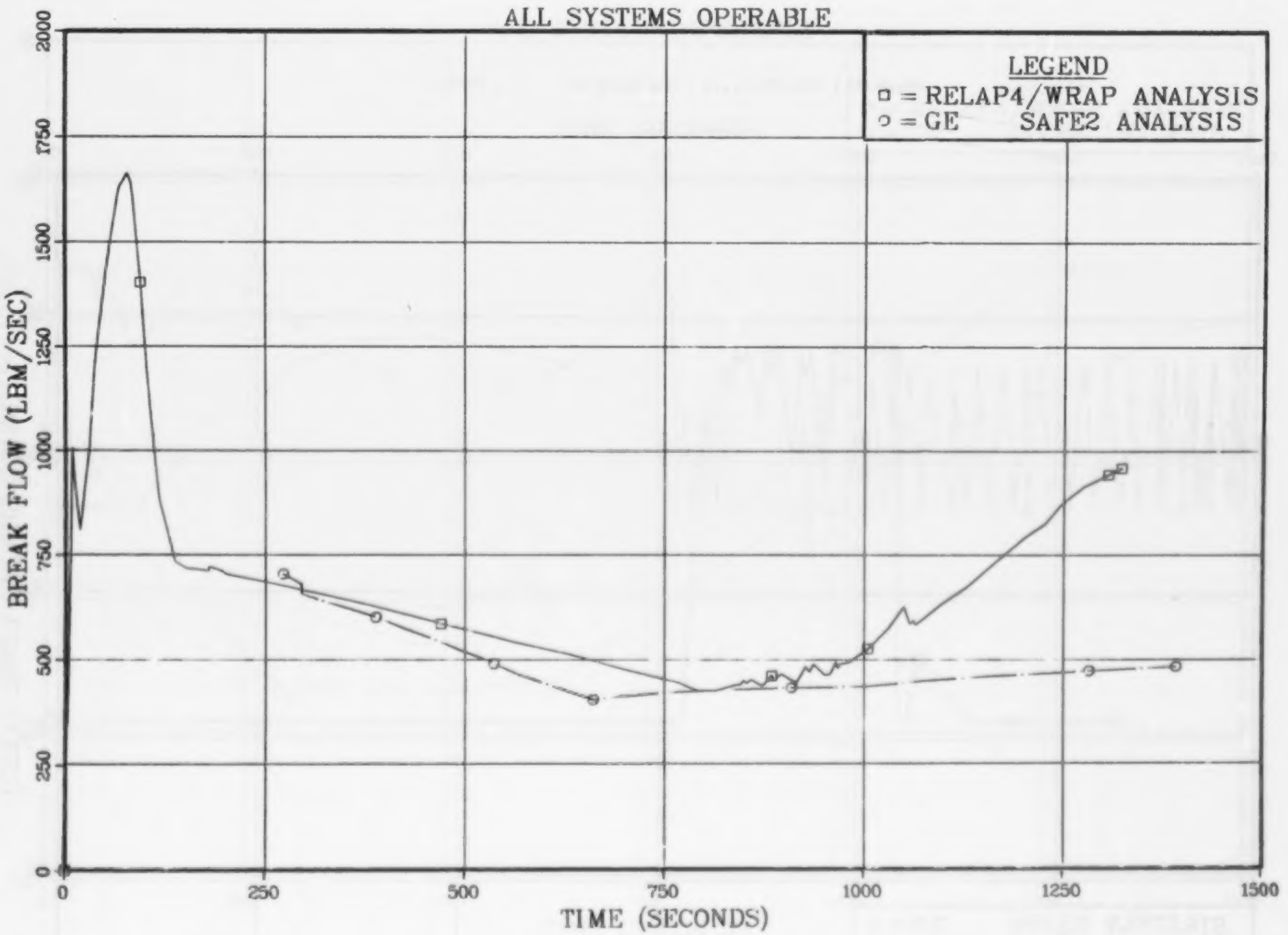


Figure F-4 GE BWR-6 0.1 Ft**2 Suction Line Break

Figure F-5

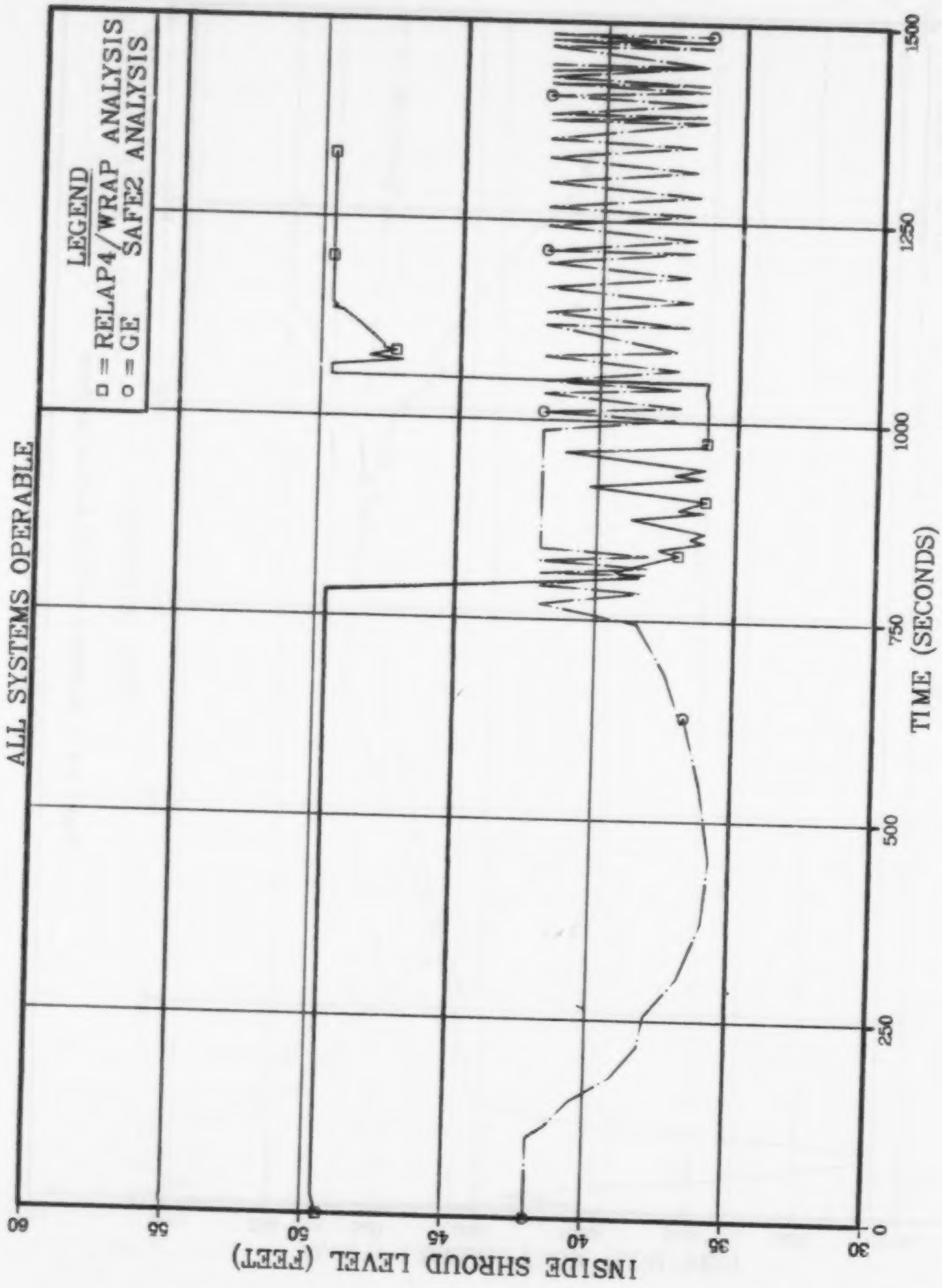


Figure F-5 GE BWR-6 0.1 Ft**2 Suction Line Break

Figure F-6

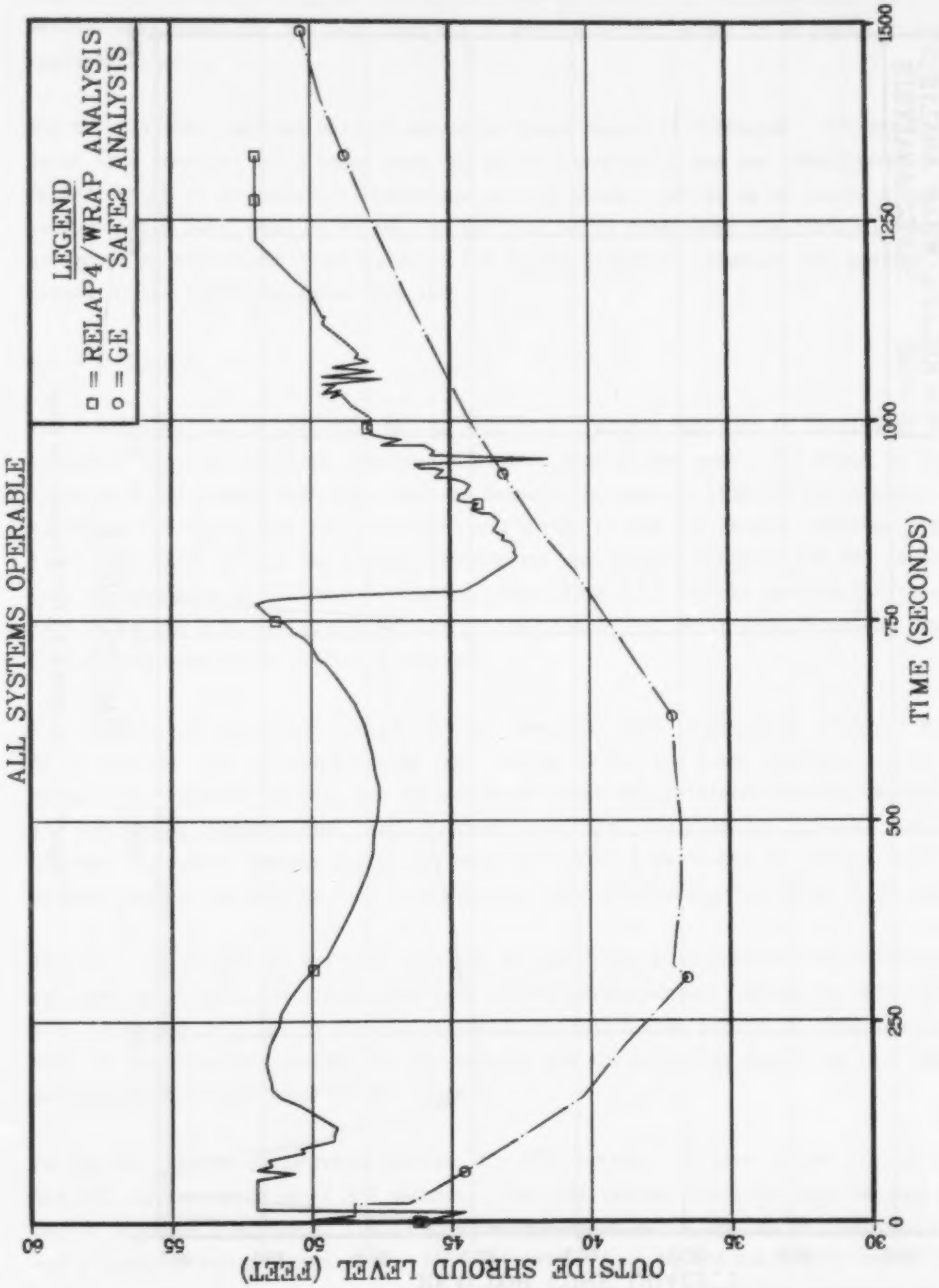


Figure F-6 GE BWR-6 0.1 Ft**2 Suction Line Break

Figure F-7

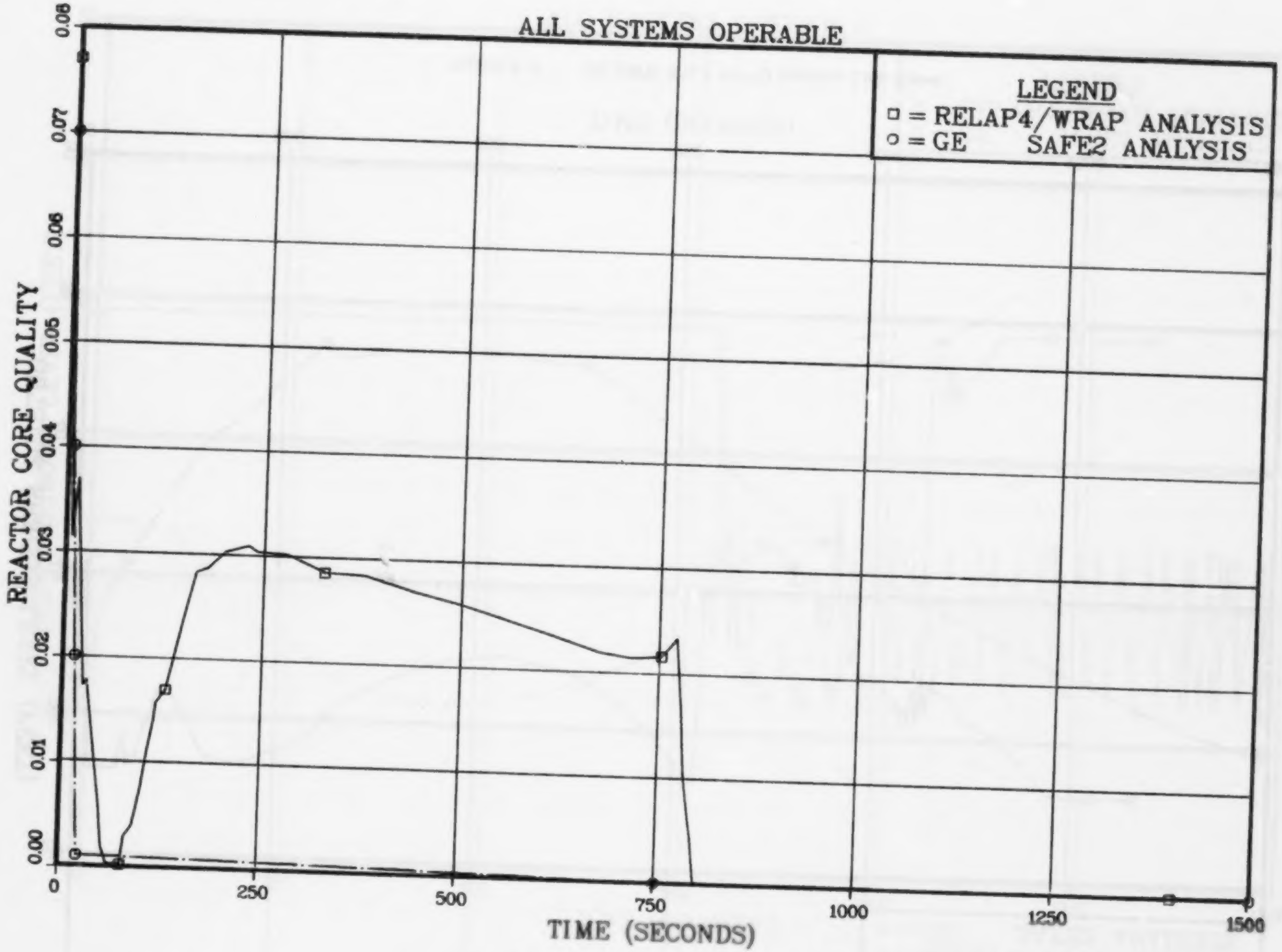


Figure F-7 GE BWR-6 0.1 Ft**2 Suction Line Break

At 1230 seconds, the system is flooded and the mixture level begins to rise through the steam dome. No core uncovery occurred during the transient for either calculation.

The RELAP 4 mixture level is compared to the SAFE level both inside the shroud and outside the shroud, in Figures F-6 and F-7, respectively. It is noted that the inside level shown for the SAFE analysis is artificially limited to 42 feet for graphical representation.

The calculational methods used to determine these levels is different. The RELAP 4 level is a computed value based upon the Wilson correlation and the IAMBLO model in RELAP4, which is an analytical technique used to prevent pancaking of liquid-steam regions. The SAFE level is an implied function which translates the fluid mixture volume to an equivalent level based on the system geometry. However, the general trends of the levels do agree favorably.

4.7.4.2 Case 2

The break involved in this case has an area of 0.1 square foot and is located at the bottom of the recirculation loop on the suction side of the pump. The break is simulated by a 0.1 square foot area junction between the suction line and containment. It is valved off during the initialization and opened at t=0.001 second. Various assumptions made which affect the system response include reactor scram at t=0.001 second, loss of feedwater at accident initiation (ramps from full flow to zero in 1.0 seconds), failure of the RCIC system and failure of the control rod drive system coolant flow. Containment remains at initial conditions.

The suction line break and scram causes an immediate drop in pressure, Figure F-8. At 10 seconds, the collapsed liquid level in the middle and lower downcomers trip the steam line isolation valves, and recirculation pumps and initiates the ADS countdown. The subsequent pressure rise peaks at about 1080 psia, the pressure turnover caused by a break flow which removes energy and mass at a rate large enough to prevent continued pressurization (see Figure F-9). In addition, the HPCS system initiates at 27 seconds.

The next 100 seconds of the transient are characterized by a constant depressurization rate and relatively even break flow rate of 800 pounds/second. Since the HPCS system flow increases only 240 to 275 pounds/second over this time period, a great deal of mass is lost from the system. At 130 seconds the ADS activates resulting in a rapid depressurization and level in all regions.

During this period of depressurization, the LPCS system initiates at 240 seconds and the LPCI system comes on at 260 seconds. The LPCI system injection into the bypass region produces a mixing of subcooled water and steam which results in condensation and a sharp 20 psi pressure drop. This initiates flows toward the bypass region with subsequent mass losses in the downcomer, plena and core. The quality increase in the core as shown in Figure F-10 is noticeable but has little immediate effect on the clad

Figure F-8

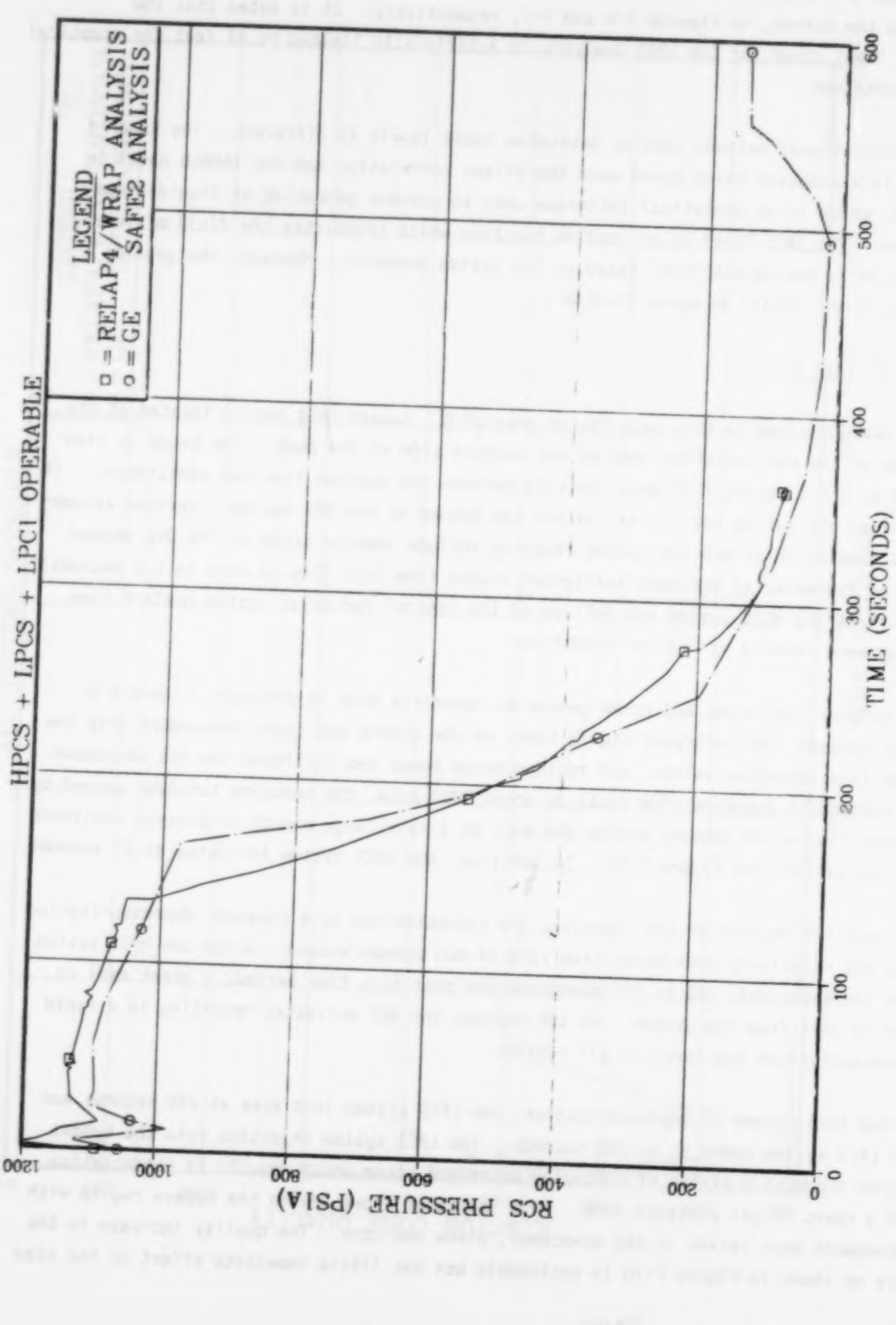


Figure F-8 GE BWR-6 0.1 Ft**2 Suction Line Break

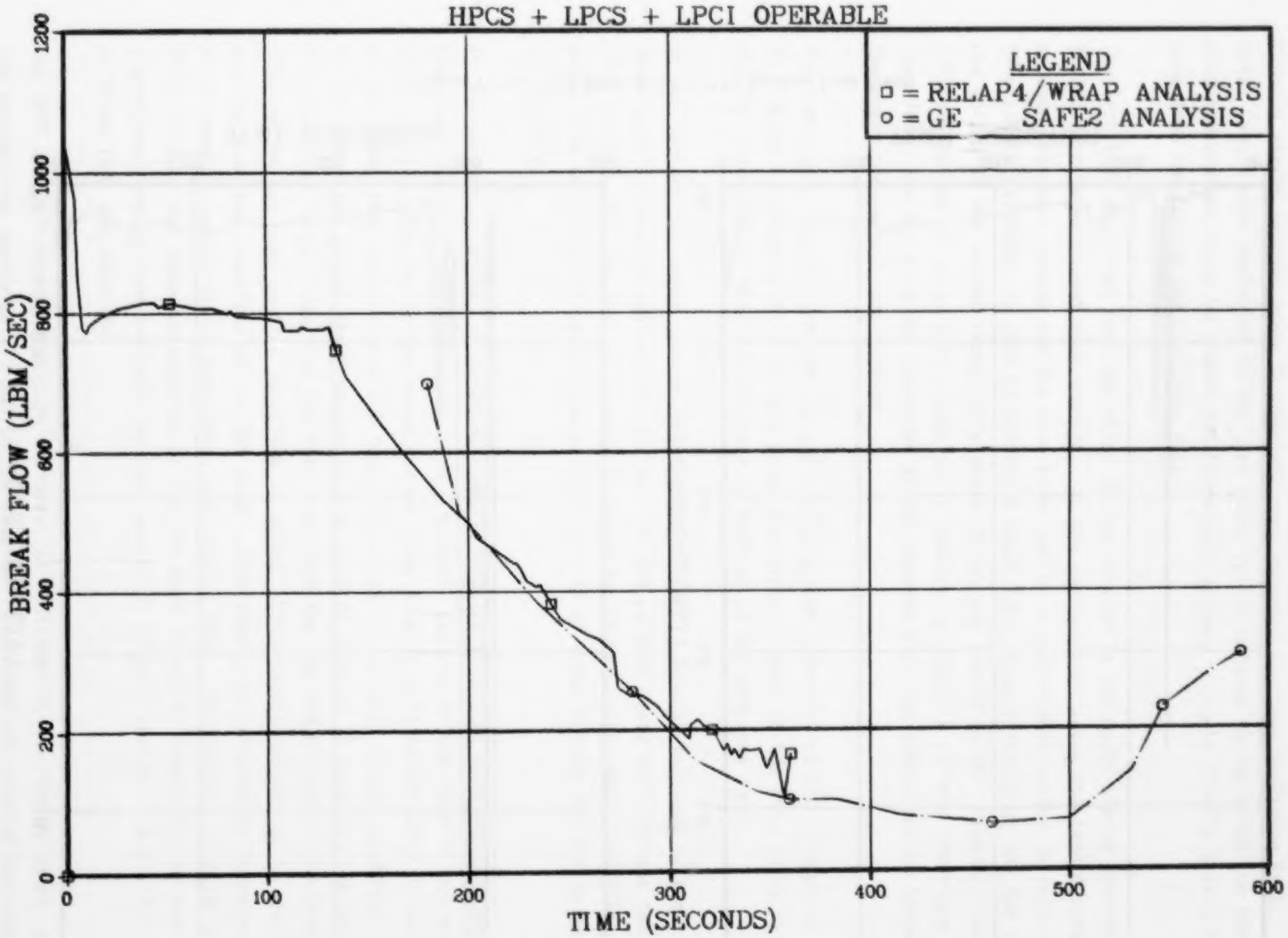
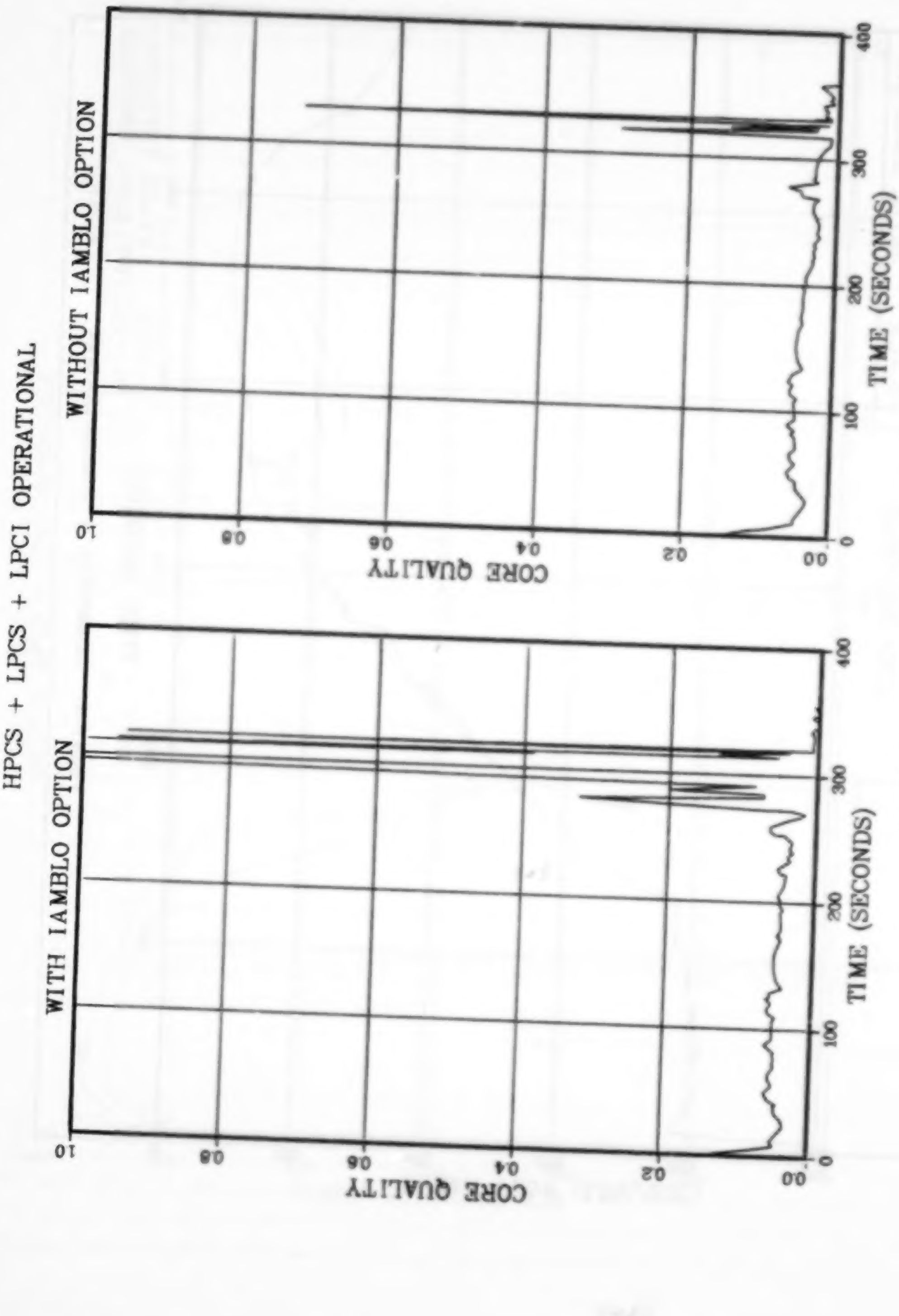


Figure F-9 GE BWR-6 0.1 Ft**2 Suction Line Break

Figure F-10


HPCS + LPCS + LPCI OPERATIONAL

WITH IAMBLO OPTION

WITHOUT IAMBLO OPTION

Figure F-10 GE BWR-6 0.1 Ft**2 Suction Line Break

temperature in the center of the core which is indicated in Figure F-11. However, this mass reduction in the core caused a change in the heat transfer mode from nucleate boiling to forced convection vaporization and the generation of steam. This steam jetting out the top of the core retards liquid from entering the core from above until finally at 295 seconds there is complete core uncovery as shown in Figure F-12. This total liquid mass depletion in the core lasts for 15 seconds during which the peak clad temperature rises by almost 100 Fahrenheit degrees. Liquid finally enters the core from the bottom and cools the fuel.

The fact that there was mass depletion in the core while the upper plenum remained filled with water caused some concern. It was decided that using the IAMBLO parameter between the upper plenum and the core might not be a justifiable option in this case. (The IAMBLO parameter is used to prevent a vapor layer from existing at the top of the one volume if the volume immediately above it has any liquid in it. However, due to CCFL at the top of core, this situation is physically possible at this interface.) Therefore, the analysis was restarted at 200 seconds with the IAMBLO option between the upper plenum and core removed.

The same basic results are seen up until LPCI system injection at 270 seconds as shown in Figures F-10 thru F-17. At this point the mixture level in the core falls briefly but the core quality does not increase as much as in the previous case.

At 300 seconds the upper plenum quality goes to zero. This is followed by flow and level oscillations throughout the system. At 320 seconds these oscillations result in core uncovery for the next 40 seconds as shown in, Figure F-12. Note that CCFL prevents water from entering the upper plenum which is full of water during the entire period of uncovery.

At 360 seconds in either calculation computational difficulties were encountered when the break junction quality becomes zero. Possibly because of the form of the momentum equation, the pressure in the break volume rises from 45 psia to 125 psia in two seconds. At the same time, water enters the core, which was filled with steam, condenses much of the vapor and causes the pressure to drop from 42 psia to 31 psia in five seconds. This produces large flows into the core from both the top and bottom. Also choked flow at the jet pump suction junctions is noted. This causes concern as to whether or not the momentum equations at the jet pump inlets should be switched to incompressible or allowed to remain in the one-dimensional mixing form. Preliminary calculations which allowed the momentum equation at the jet pump inlets to remain in the one-dimensional mixing form indicate the core would not totally uncover. A minimum level of three feet was observed.

The SAFE analysis showed some core uncovery, as indicated by the inside level, during the period from approximately 150 to 300 seconds. SAFE heat-up calculations were not presented. The inside shroud level comparisons are shown in Figure F-13. For reference to the SAFE data, the top of the active core is at 30 feet, and the bottom of the active core is at 17.5 feet.

Figure F-11

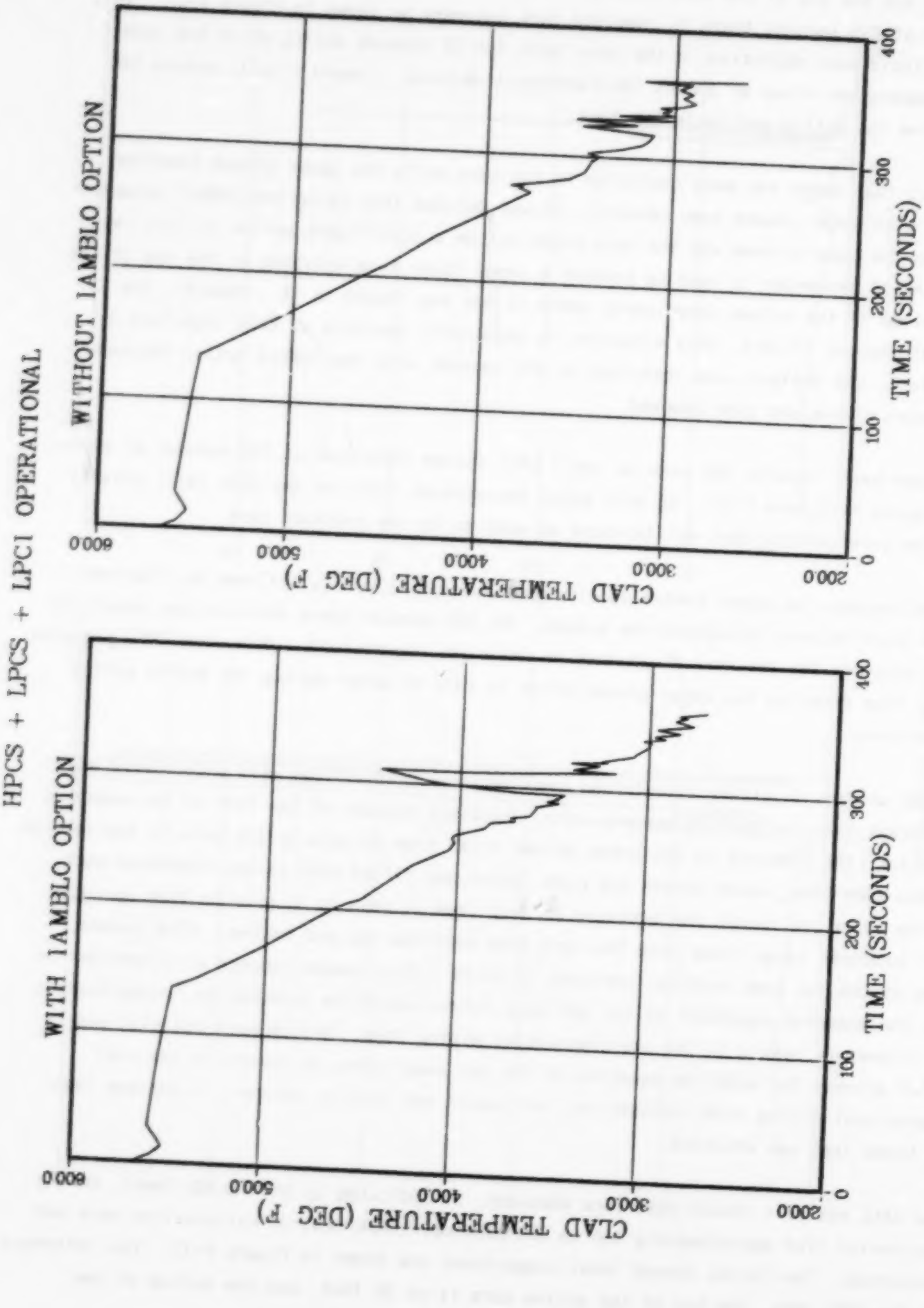


Figure F-11 GE BWR-6 0.1 Ft**2 Suction Line Break

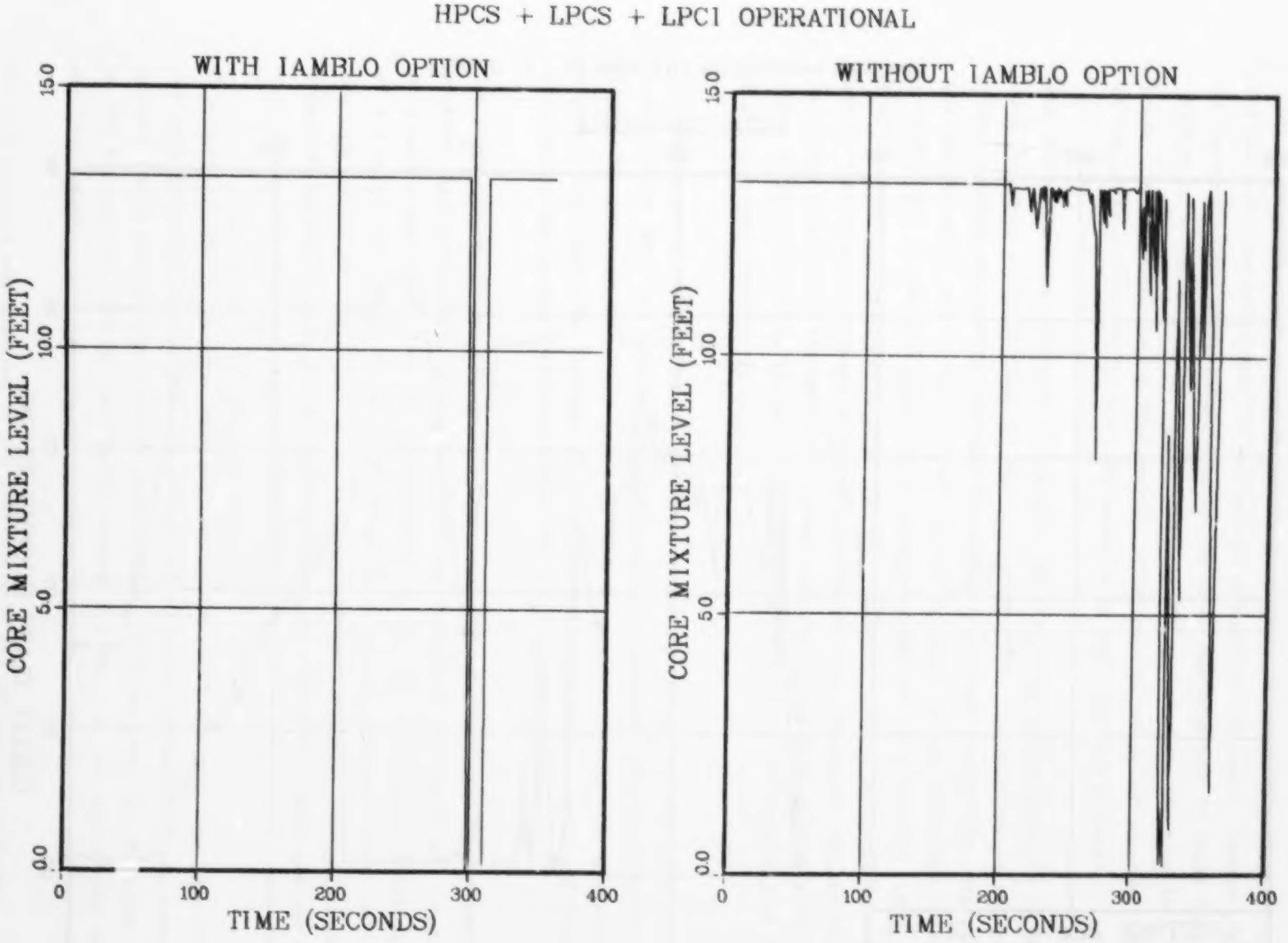


Figure F-12 GE BWR-6 0.1 Ft**2 Suction Line Break

Figure F-13

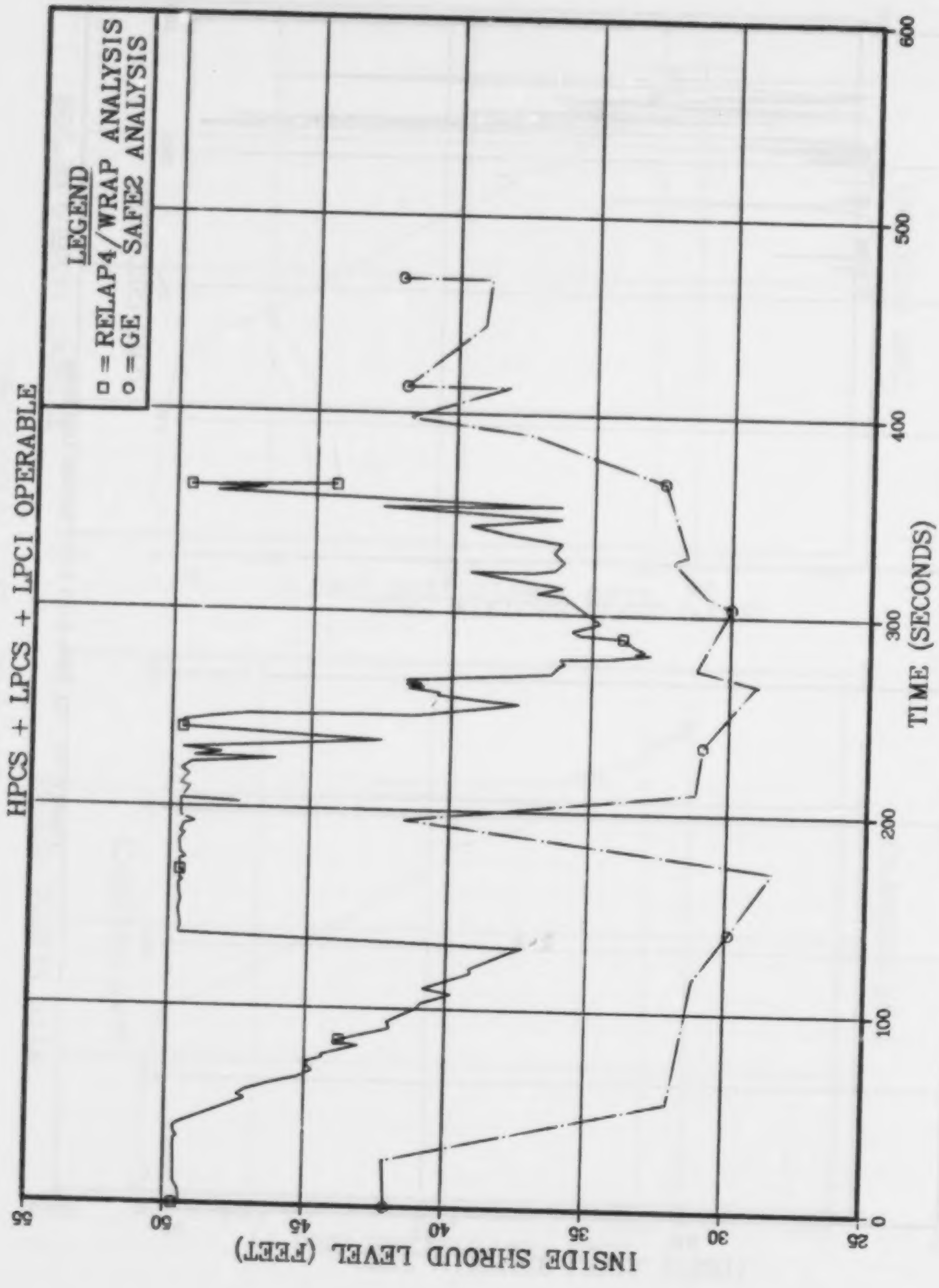


Figure F-13 GE BWR-6 0.1 Ft**2 Suction Line Break

4.7.4.3 Case 3

This break is modeled by a 0.2 square foot junction between the steam dome and the containment. Failure of the feedwater, RCIC system, and low pressure coolant systems is assumed in this analysis. The break is assumed to be inside containment so isolation of the containment will not isolate the break. Due to an input error that was not noticed, the containment is not kept at atmospheric pressure. However, this error in the containment backpressure (increasing up to approximately 50 psia) does not alter significantly the results up to approximately 300 seconds into the transient since the break flow is choked during this period. After approximately 300 seconds, the effects of the error on the results are considered to be small for our purposes.

The steam line break produces a much more rapid initial loss of pressure in the steam dome than does a liquid break as shown in Figure F-14. System pressure decrease causes voiding and quality increase throughout the system (except the core whose quality decreases due to loss of heat source). Voiding in the downcomer region results in a decrease in the collapsed liquid level tripping the recirculation pumps, steam line isolation valve and initiating the ADS countdown. Since the break is relatively small, isolation is followed by an abrupt pressure rise. However, because the break is in the steam line, there is still a very low resistance path available for the steam to escape from the system. Thus the pressure rise in the steamdome is not as high as in the liquid break cases.

During the above time period, GE indicates a sharp pressure dip beginning at t=0.0 and ending after about one second, presumably due to a complete loss of feedwater at that time. The pressure then rises until 15 seconds at which time another pressure drop occurs. The steam line isolates at 29 seconds which produces a small and brief pressure rise before the system continues toward its final depressurization.

The break quality in the NRC staff calculations indicates a predominantly two-phase mixture leaving the break during the first two minutes of the transient. This leads to a much higher break flow than is predicted by GE. GE calculates a break quality of 1.0 until the system floods to the break level at 720 second as shown in Figure F-15. The combination of this effect at early times and the large flow through the ADS after 130 seconds results in the staff's prediction indicating a much greater mass loss during the transient than GE calculates.

Flow oscillations in the core were observed in the staff analysis from approximately 260 seconds to 350 seconds when the effects of CCFL were evidently strong enough to prevent the return of flow from the upper plenum. Core uncovery was observed from 400 to 480 seconds with quality oscillating between 0.6 and 1.0. No significant heat-up was calculated.

No core uncovery was observed in the SAFE analysis and ADS was not actuated. It is the staff's judgment that the SAFE level swell model prevents the break mixture from becoming two-phase, and hence prevents the required mass depletion to trip the ADS.

Figure F-14

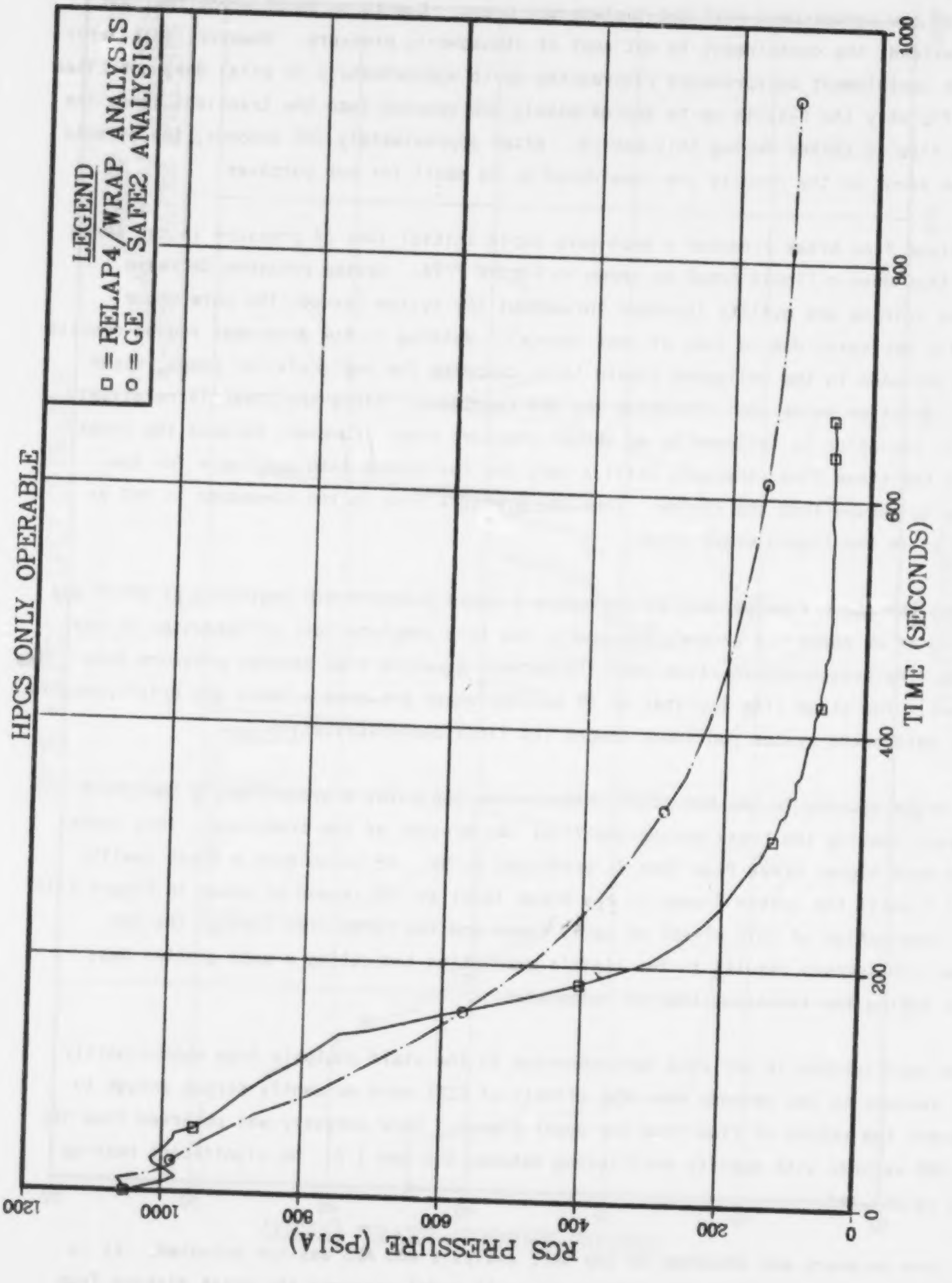


Figure F-14 GE BWR-6 0.2 Ft**2 Steam Line Break

Figure F-15

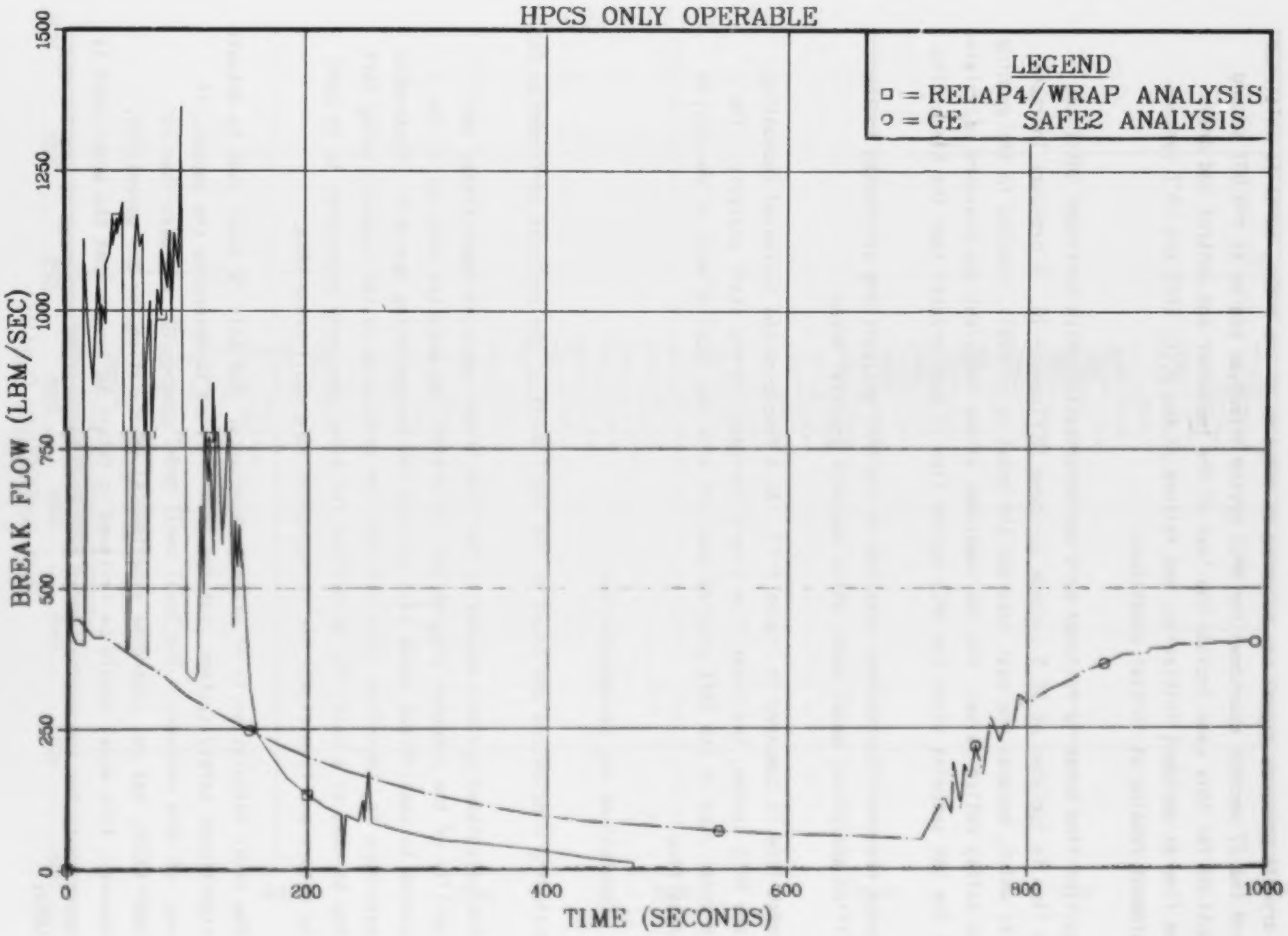


Figure F-15 GE BWR-6 0.2 Ft**2 Steam Line Break

4.7.4.4 Case 4

This analysis concerns a 0.001 square foot break in the suction side of a recirculation loop. The valves are instantaneously opened at t=0.001 seconds. Since GE assumes a high drywell pressure signal has occurred at the time of the break, scram is initiated and and the 27 seconds countdown for HPCS system injection begins at t=0.001 second. Assumptions for this case include the loss of the feedwater and control rod drive system flow at accident initiation, and failure of the RCIC, LPCS and LPCI systems. Containment remains at initial conditions.

The suction line break is followed by a depressurization which continues until the steam line is isolated at 10.5 seconds as shown in Figure F-16. A pressure increase results which, because the mass loss out the break is so small, results in the opening of the safety relief valve. For the remainder of the transient the pressure oscillates about the SRV setpoint since the HPCS system flow is much greater than the break flow.

The large pressure fluctuations observed in the SAFE analysis are attributed to the simplified analytical model used, which neglects inertial terms.

The break flow is compared in Figure F-17. As a result of the increased subcooling, from the HPCS system, the break flow slowly increases in the staff analysis. The simple model used in the SAFE program does not show the local effects of density on the break flow.

4.7.5 Conclusions and Recommendations

The following conclusions are based on the staff audit of the analyses performed by GE:

(1) The calculated system response to the four breaks analyzed demonstrates the ability of the computer program SAFE to predict the expected behavior of the system to small-break LOCAs with various ECC systems being operable. Reasonable assurance is, therefore, provided that the calculated system response using SAFE may be used as a basis for guidelines for plant emergency procedures to be used to detect and to mitigate the consequences of a small-break LOCA.

(2) The level calculation is of primary importance. Not only is level used to actuate significant safety systems, but the level is used to determine the amount, if any, of core uncovery. The level swell model used by GE, and described in NEDO-10329, has not undergone experimental verification for BWR geometries. However, this model should be reviewed in detail to assure that the model used is appropriate for the evaluation of peak clad temperature responses to small-break LOCAs.

(3) The models and current modeling procedures used for the staff analyses should be reviewed, and revised, as necessary to remove the difficulties experienced during

Figure F-16

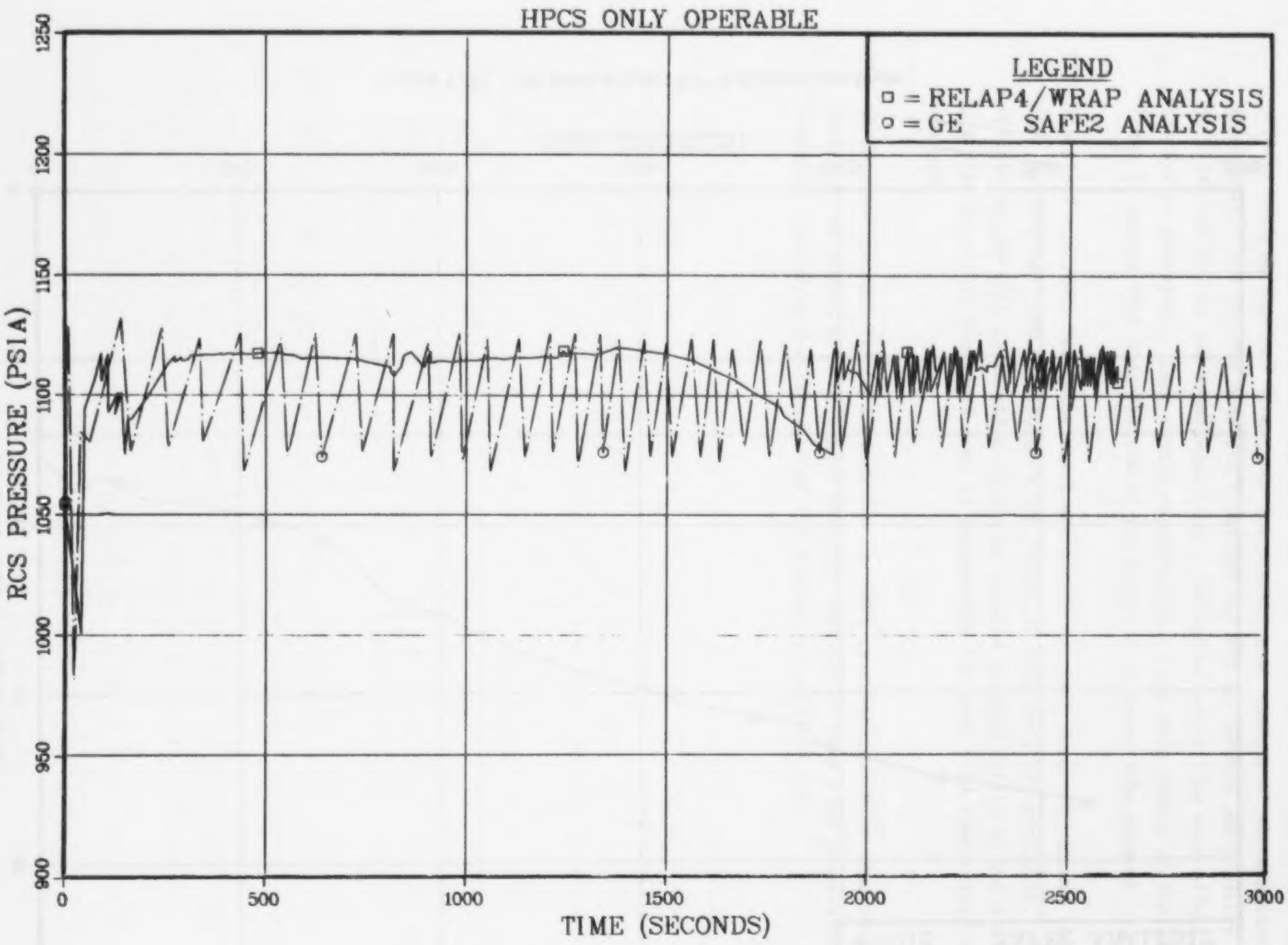


Figure F-16 GE BWR-6 0.001 Ft**2 Suction Line Break

Figure F-17

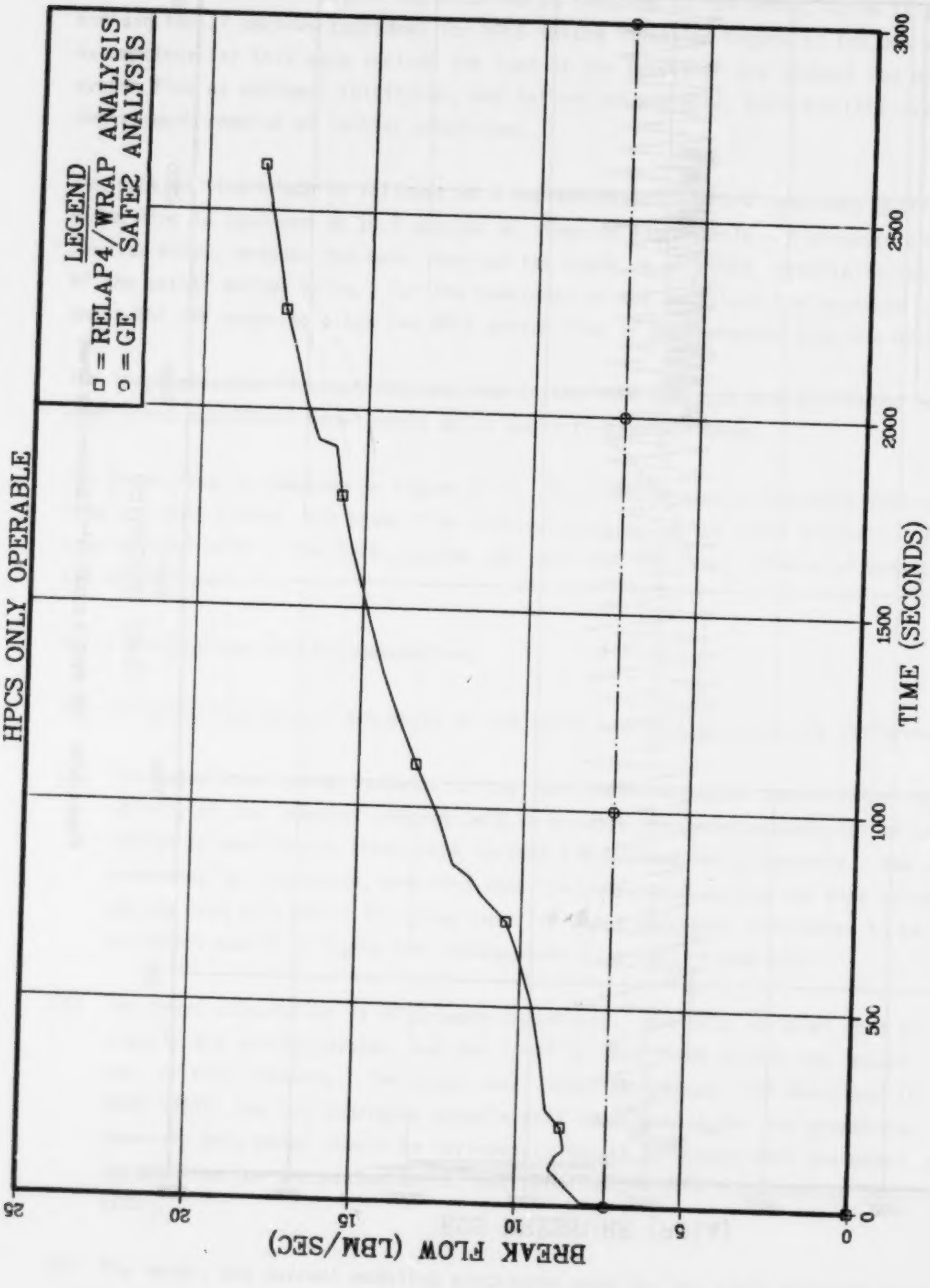


Figure F-17 GE BWR-6 0.001 Ft**2 Suction Line Break

the audit analyses. Particular attention should be given to the level calculation obtained by RELAP/4/MOD/5.

(4) The single, spacially-uniform pressure model used by GE, which neglects local effects such as inertial terms, can not predict some aspects of the expected transients. The initial pressure fluctions may not be correct and pressure oscillations may be too pronounced (e.g., the relief valve flow rate effect on the system pressure). Care should be exercised in the development of the guidelines to assure that this feature of the analysis is taken into account.

(5) The staff analyses, for those cases where core uncovery occurred, showed that the CCFL is important and can increase the amount of core uncovery predicted. The effects of the CCFL calculation should be studied in more detail in the staff analyses to assure the model used is appropriate for peak clad temperature response analyses.

(6) GE does not account for CCFL in SAFE. For SAFE calculations which show core uncovery, GE should provide a more detailed analysis of peak clad temperature response, including a discussion of the assumption used for CCFL.

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APPENDIX G

GENERAL CONCLUSIONS, FINDINGS, AND RECOMMENDATIONS

1. GENERAL CONCLUSIONS

In early June 1979, the B&OTF initiated a review of BWRs to verify that, in light of the TMI-2 experience, continued operation of the BWRs is acceptable, or is acceptable provided that certain changes are made in their design and, operation, and training of operators. The scope of the review focused on loss of feedwater events, small-break LOCAs, development of guidelines for the preparation of emergency operating procedures, and operator training in these procedures.

The review revealed that the BWR systems are quite capable of coping with small breaks and with feedwater transients, with or without stuck-open relief valves. Therefore, continued operation is acceptable. The BWRs have multiple safety systems which can provide core cooling in the event of transients and accidents. The ability to quickly depressurize and use low pressure systems if high pressure systems fail adds significantly to the capability of the BWRs to cope with the events reviewed. Also, the BWRs are designed to operate with voids in the upper part of the reactor vessel and are designed to operate with natural circulation of coolant through the core. A reliable level measurement system provides the operator with a good measure of vessel water inventory.

The review did identify improvements in systems, procedures, and analyses which will make the BWRs even less susceptible to core damage during accidents and transients coupled with equipment failures or operator errors. These changes are generally of a nature that they should be implemented as soon as practicable. This means that the system design changes should be started now with implementation on operating plants by January 1981, or shortly thereafter, subject to justification by individual licensees. Some of the recommendations call for analysis of options for system improvements with no specific details. These recommendations will require additional interaction between GE, the Owners Group, the utilities, and the NRC staff for resolution. Emphasis should be placed on getting workable systems, not on meeting arbitrary implementation schedules. The list of recommendations is given in Section 4 of this report.

2. PLANT DESIGN

For a small-break LOCA or a loss of feedwater with other failures (e.g., stuck-open relief valve or failure of the RCIC system), high drywell pressure or low reactor vessel water level will actuate the ECC system to maintain core cooling. The operator monitors vessel water level and flow into the vessel to deterine when ECC system flow should be throttled or terminated.

Instrumentation available for the operator to monitor the course of the event (e.g., vessel water level, ECC system flows, core flow, system pressure, and process radiation levels) is adequate for proper diagnosis of the event. Our review of the level instrumentation has revealed that it may give inaccurate level indications, but the indications will be sufficiently accurate to provide the required automatic actuations and to serve as a useful guide for operator actions. Also, level recording may be in error by as much as 28 inches due to high drywell temperatures, but the normal control range on level, the level range which the operator would use as a guide in throttling or terminating ECC system flow, is typically 17 or 18 feet above the top of the fuel; therefore, the error in level indication or recording is not large enough to mislead the operator as to whether or not the fuel is covered with water at the time he would throttle or terminate ECC system flow.

The major system or design recommendations in Section 4 of the this report relate to centralizing level recording instruments and modifications to ECC system logic to reduce the number of actions required by the operator. Analyses have shown that for the degraded case of loss of feedwater, stuck-open relief valve, and no high-pressure systems operable, operator action to depressurize the reactor so that the low pressure systems can be used is required in less than ten minutes. Modifications to preclude the need for such rapid operator action are recommended in Section 4 of this report.

3. OPERATIONS

3.1 Training

Operator training has evolved over the last 10 to 15 years from concentrated on-the-job training programs to the more formal NRC-approved programs of today. In the past, training programs have underemphasized nonstandard passive conditions such as misaligned systems, undetected failures of emergency safety features equipment, and multiple failures. Irrespective of the merits of the single failure criterion as a design basis, it should not be considered as a limiting basis for training purposes. Recommendations in Section 4 of this report regarding training concentrate on simulator training with inclusion of non-design-basis transients and multiple failures in control and safety systems. Training on protecting the core should be emphasized on all plants.

3.2 Operating Procedures

Each normal operating procedure involves the use of checklists and is based on a controlled evaluation giving final conditions as goals to achieve. On the other hand, abnormal and emergency procedures are completely different in that the operator is confronted with automatic responses for which he may have to take manual actions. Therefore, in preparing abnormal and emergency procedures, consideration should be given to the real time that it takes for systems to respond and for the operator to perform manual functions. Procedures should be written to address multiple equipment failures.

Aids to assist the operator in diagnosing instrument response should be part of the emergency procedures. Emergency procedures should be written in a manner to assure that the operator is aware of instrumentation available to monitor the systems and to verify that the system parameters are satisfactory. The procedures should address expected instrumentation response and what operator actions are required in the event of unexpected instrument response. Procedures should be clear and unambiguous. Recommendations are provided in Section 4 of this report.

3.3 Human Factors

The operator has been trained to believe his instrumentation. However, he must be trained to not rely on a single instrument since any single indication may be erroneous and misleading under certain conditions.

The operator should monitor the control board and evaluate all parameters of concern by the appropriate checking of other instrumentation. He must perform this cross-check to verify instrument display. If he has additional manual actions to perform, he may reduce his observation on other system parameters that may lead to "tunnel vision." Recommendations are provided in Section 4 of this section.

4. STANDARD REVIEW PLAN

A reassessment of moderate-frequency and infrequent events and their treatment by the NRC is necessary. Contrary to Standard Review Plan requirements, anticipated operational occurrences plus a single failure have not been rigorously pursued, especially with regard to a stuck-open safety/relief valve during a transient. Such events were considered either to be within the capability of the makeup system or were covered by small-break LOCA analyses. It is apparent that greater awareness of these review areas and assumptions is necessary. In no case, however, would the present Standard Review Plan require that multiple failures similar to those associated with the TMI-2 accident be considered in a design basis accident. Greater attention will be needed in considering consequential failures and operator actions. Recommendations are provided in Section 4. of this report.

5. GENERAL DESIGN CRITERIA

Feedwater transients are anticipated operational occurrences since they are expected to occur one or more times during the life of a plant. The basic requirements for anticipated operational occurrences are given in General Design Criteria 10 and 15. Additional requirements are specified in General Design Criteria 13 and 14. These criteria appear to have been met for BWRs, even in the light of the TMI-2 experience.

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APPENDIX H

AUDITS OF SMALL-BREAK LOCA EMERGENCY PROCEDURES AND OPERATOR RETRAINING AT SELECTED GE BWR OPERATING PLANTS

1. INTRODUCTION

On December 10-13, 1979, representatives of the B&OTF, accompanied by the cognizant Division of Operating Reactors Project Manager and Office of Inspection and Enforcement Regional/Resident Inspector(s) conducted audits of the emergency procedures and operator retraining associated with small-break LOCAs at the Nine Mile Point 1, FitzPatrick, and Dresden 2/3 plants. A number of NRC representatives also visited GE's BWR Simulator at Morris, Illinois, to observe its responses to a small-break LOCA.

2. BACKGROUND

The purpose of the B&OTF audits was to review selected licensees' emergency procedures, operator retraining, operator awareness of the emergency procedures and their bases, and systems considerations associated with small-break LOCAs. The Nine Mile Point 1, FitzPatrick, and Dresden 2/3 plants were selected for the B&OTF audits based on their representation of different BWR classes and licensees and on the limited time available to conduct the audits. Audits of the remaining GE-designed BWR operating plants are being conducted by IE.

The licensees' small-break LOCA emergency procedures and operator retraining were based on operator guidelines developed by the Owners Group which, as documented in its letter to the Owners Group dated October 26, 1979, have been approved by the B&OTF. As set forth on Page 5 of Enclosure 6 to Darrell G. Eisenhut's letter to all operating plants dated September 13, 1979, the small-break LOCA emergency procedures and operator retraining were to have been implemented by December 31, 1979.

3. PLANT AUDITS

The following matters were considered at each of the plant audits:

Emergency Procedures

The licensee's small-break LOCA emergency procedures were compared to the approved operator guidelines. The clarity of the procedures in terms of individual operator actions and cautions and the flow of the procedures with respect to the timely initiation of operator actions were considered.

Operator Retraining

The retraining that the operators received with respect to the small-break LOCA emergency procedures was reviewed. Informal training, formal classroom study, and walk-throughs of the emergency procedures with their shift supervisors or training coordinators were considered.

Operator Awareness of the Emergency Procedures and their Bases

The operators' understanding of small-break LOCAs, the differences between small-break LOCAs and other depressurization events, and the bases for the approved guidelines, and their familiarity with the small-break LOCA emergency procedures were reviewed. The effectiveness with which the emergency procedures can be carried out was considered.

Systems Considerations

Systems-related aspects of the emergency procedures were reviewed to assure that the necessary operator actions can be performed.

4. FINDINGS

The most significant findings resulting from the plant audits are summarized below:

Emergency Procedures

For the most part, each of the licensees' emergency procedures reflected all of the essential elements of the approved operator guidelines. In fact, at one plant, the emergency procedures were little more than the guidelines themselves. Consequently, they differed significantly in both format and content from the licensee's other emergency procedures. Several of the licensees' emergency procedures appeared to be somewhat too detailed, especially in the automatic actions and immediate operator actions sections.

In several instances, caution statements were placed in the immediate operator actions sections of the emergency procedures. It was generally felt, however, that this practice should be either minimized or eliminated. There was considerable discussion concerning the most appropriate sections of the emergency procedures in which to place the caution statements. One licensee expressed concern that the placement of caution statements in the discussion sections of the emergency procedures could result in their being overlooked. There appeared to be no consensus concerning the best placement of the caution statements in the emergency procedures. In one licensee's emergency procedures, the caution statement concerning the effects of drywell temperature on reactor vessel level measurement was omitted. The licensee maintained that this matter can be addressed best during operator retraining.

There was considerable discussion concerning whether certain operator actions, such as verification of the automatic transfer of the HPCI system suction from the condensate storage tank to the suppression pool and verification of automatic containment isolation by independent means, should be placed in the immediate operator actions section or the subsequent operator actions section of the emergency procedures. Again, there appeared to be no consensus concerning the placement of such operator actions in the emergency procedures.

Finally, one licensee expressed concern that the NRC was becoming too prescriptive in the writing of emergency procedures.

The emergency procedures had been approved for use at all three plants but had actually been implemented at only one plant at the time of the audits. At the plant at which the emergency procedures had been implemented, however, not all the operators had completed their retraining or, for that matter, had even been required to read the emergency procedures. For this plant, the existing LOCA emergency procedures were revised to incorporate the essential elements of the approved guidelines, hence, no separate small-break LOCA emergency procedures existed. The licensee maintained that the revisions to its existing LOCA emergency procedures were minor and, therefore, the revised emergency procedures could be implemented prior to the completion of operator retraining. Nevertheless, the potential existed for an operator to be called upon to use an emergency procedure that he had never seen.

Operator Retraining

At the time of the audits, none of the licensees' operators had completed all of their retraining associated with the small-break LOCA emergency procedures. Two of the licensees had instructed their operators to review the emergency procedures on their own, however, only approximately one-half of these operators had completed their reviews at the time of the audits. Two of the licensees planned formal classroom training sessions for their operators (the other licensee planned either a brief formal classroom session or walk-throughs of the emergency procedures with their shift supervisors or training coordinators), however, only a few of these operators had attended the training sessions at the time of the audits. Two of the licensees planned walk-throughs of the emergency procedures for their operators with their shift supervisors or training coordinators. The other licensee did not plan walk-throughs on the basis of the similarity of its small-break LOCA emergency procedures to its present LOCA procedures. Only one of the licensees indicated that it intended to utilize a simulator as part of its operator retraining.

Operator Awareness of the Emergency Procedures and Their Bases

The operators from two of the plants exhibited a reasonably good understanding of the emergency procedures and their bases. These operators also appeared to be capable of effectively carrying out the emergency procedures. However, the operators of the other plant exhibited a less-than-desirable understanding of the emergency procedures and their bases. The capabilities of these operators to effectively carry out the emergency procedures also appeared to be less than desirable.

Nearly all of the operators exhibited a less-than-desirable understanding of the reactor vessel level instrumentation. Notably deficient was the operators' understanding of temperature effects on the vessel level instrumentation, how temperature compensation is achieved, and the vessel locations from which the levels are being measured. A few of the operators did not know such things as the means by which safety/relief valve position indication is derived, the location of the isolation condenser isolation indicators, and the purpose of the isolation condenser bypass controls. In addition, substantially different answers were received on how to verify that containment isolation had occurred.

While describing how the emergency procedures would be carried out in the control rooms, a significant number of the operators overlooked several vital operator actions, such as the verification of reactor scram. For those cases in which one emergency procedure, such as the small-break LOCA procedure, refers to another procedure, such as the reactor scram procedure, it was not clear to the operators which procedure takes precedence; e.g., whether the operator should complete the referenced procedure before proceeding on to the next action statement of the parent procedure.

Systems Considerations

For the most part, the instrumentation and controls associated with those systems required to mitigate the consequences of small-break LOCAs were such that the necessary operator actions can be performed without undue difficulty. With the exception of the instrumentation required to verify Group 2 containment isolation of a limited number of small lines, all instrumentation and controls were located in the control rooms on cabinet panels facing, and in immediate proximity to, the operators. The instrumentation required to verify Group 2 containment isolation of a limited number of small lines was also located in the control rooms, but on cabinet panels behind the main control complex.

Two licensees' operators pointed out that the separation of the instrumentation and controls necessary to mitigate the consequences of small-break LOCAs contributed some difficulty to the operators in performing their necessary actions, especially in those situations in which only a single operator is available. An example of this is the separation of the reactor vessel level instrumentation from the controls used to manually actuate the automatic depressurization system. The availability of at least two operators, as was the case in one of the plants, substantially compensated for this separation.

One licensee's operator suggested that the addition of a timer which could be used in conjunction with the manual initiation of the automatic depressurization system would be helpful. Another licensee's operator, noting that the zero indications of the various reactor vessel level instrumentation often refer to different reactor vessel levels, suggested that the potential for operator error would be substantially reduced if all the reactor vessel level instrumentation were referenced to the same reactor vessel level.

Conclusions from Audits

At the conclusion of each of the plant audits, each licensee was asked if, in its opinion, the efforts involved in developing the emergency procedures and the retraining of its operators have enhanced the capabilities of its plant and its operators to cope with small-break LOCAs. The answer given by each licensee was the affirmative. The reasons given included the collective contributions of a larger-than-normal number of individuals representing various interests in the development and approval of the operator guidelines, the increased attention given by the Owners Group and the licensees in the development of the emergency procedures, and the additional specialized operator retraining.

5. SIMULATOR VISIT

A number of those NRC representatives who participated in the audit of the Dresden 2/3 plant visited GE's BWR Simulator to observe its responses to a small-break LOCA. The particular scenario represented involved a small break in a main steam line inside containment combined with a total loss of offsite power.

The capability of the simulator to adequately represent a small-break LOCA was found to be limited. In the above scenario, the small break had to be represented by opening a safety/relief valve. A fully-open safety/relief valve, however, represents a somewhat larger break area than is of particular interest in the study of small-break LOCAs. In addition, since the safety/relief valves discharge to the suppression chamber, the drywell pressure and temperature do not increase as they would in the event of a small-break LOCA inside containment. The increase in drywell pressure and temperature had to be initiated by turning off the drywell coolers. The GE representatives indicated, however, that in the near future, they expect to upgrade the capability of the simulator to more adequately represent small-break LOCAs. Additional features presently under consideration include the capability to represent various sizes of small-break LOCAs at a number of different locations.

6. CONCLUSIONS

On the bases of the findings resulting from the B&OTF audits of the Nine Mile Point 1, FitzPatrick and Dresden 2/3 plants, it was concluded that the BWR plant licensees' emergency procedures and operator retraining associated with small-break LOCAs could be implemented by December 31, 1979, as required. It was further concluded that the licensees' emergency procedures and operator retraining associated with small-break LOCAs provide added assurance that the BWR plants and their operators could accommodate a small-break LOCA in a acceptable manner.

7. RECOMMENDATIONS

As a result of the B&OTF audits of the emergency procedures and operator retraining associated with small-break LOCAs at the Nine Mile Point 1, FitzPatrick, and Dresden 2/3 plants and the visit to GE's BWR Simulator, several areas were identified in which the need for improvement is indicated. It is recognized that the need for improvement in at least some of these areas existed prior to the licensees' efforts related to small-break LOCAs or as a result of the audits being conducted several weeks before the date that the efforts were required to be completed. The areas in which the need for improvement is indicated and the recommendations for improvement are as follows:

Emergency Procedures

On the bases of their reflection of the essential elements of the approved operator guidelines and their status of implementation, it was concluded that the licensees' small-break LOCA emergency procedures could be implemented by December 31, 1979, as required. However, on the bases of the potential problems associated with the use and placement of caution statements, placement of operator actions statements, and implementation practices associated with the emergency procedures, it is recommended that the NRC, in collaboration with the nuclear industry, develop guidance, perhaps in the form of a regulatory guide, on the format, content, and implementation of emergency procedures.

Operator Retraining

On the basis of their status of completion, it was concluded that the licensees' operator retraining associated with small-break LOCAs could be completed by December 31, 1979, as required. However, on the bases of the substantial disparity in the emphasis the licensees placed on the operator retraining associated with the small-break LOCA emergency procedures, it is recommended that the NRC, in collaboration with the nuclear industry, develop guidance, perhaps in the form of a regulatory guide, on the extent of operator retraining appropriate to the implementation of new or revised emergency operating procedures.

Operator Awareness of the Emergency Procedures and Their Bases

On the bases of a significant number of operators' less-than-desirable understanding of the emergency procedures and, especially, their bases, it was concluded that the licensees' operator retraining is less than desirable. Accordingly, it is recommended that the licensees reassess their operator retraining in order to assure that their operators thoroughly understand the emergency procedures and their bases.

Systems Considerations

On the bases of the plants' complements and locations of the instrumentation and controls associated with those systems required to mitigate the consequences of small-break LOCAs, it was concluded that the necessary operator actions can be performed without undue difficulty. However, on the bases of the potential problems associated with the zero indications of the various reactor vessel level instrumentation often referring to different reactor vessel levels, it is recommended that both the NRC and the nuclear industry consider the establishment of a requirement that all reactor vessel level instrumentation be referenced to the same reactor vessel level.

Simulator

On the basis of the limited capability of the simulator to adequately represent a small-break LOCA, it was concluded that the simulator is presently of little value in representing or retraining operators in plant responses to small-break LOCAs. Accordingly, it is recommended that GE, in collaboration with the NRC and the nuclear industry, pursue in an expeditious manner upgrading the capability of the simulator to more adequately represent small-break LOCAs including the capability to represent various sizes of small-break LOCAs at a number of different locations.

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13. TYPE OF REPORT

PERIOD COVERED *(Inclusive dates)*

14. *(Leave blank)*

15. SUPPLEMENTARY NOTES

16. ABSTRACT *(200 words or less)*
The results of the Bulletins & Orders Task Force's generic evaluation of feedwater transients, small break loss-of-coolant accidents, and other Three Mile Island Unit 2 related events for General Electric Company-designed operating plants and near-term operating license applications to confirm or establish the bases for the continued safe operation of the operating plants are summarized. As a result of its review, the Bulletins & Orders Task Force has concluded that (1) the continued operation of the General Electric Company-designed operating plants is acceptable provided that certain actions related to the plants' designs and operation, and training of operators are implemented consistent with the recommended implementation schedule, and (2) the actions taken by the licensees with General Electric Company-designed operating plants in response to Office of Inspection & Enforcement Bulletin 79-08 provide added assurance for the protection of the health and safety of the public. In addition, the Bulletins & Orders Task Force has independently confirmed the safety significance of those related actions recommended by other Office of Nuclear Reactor Regulation task forces.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT
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19. SECURITY CLASS *(This report)*
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